STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

February 18, 2011 - 10:15 a.m.
Concord, New Hampshire

RE: **DG 08-048**
UNITIL CORPORATION AND NORTHERN UTILITIES NATURAL GAS:
Joint Petition for Approval for Stock Acquisition.
(Status conference)

PRESENT: Chairman Thomas B. Getz, Presiding
Commissioner Clifton C. Below
Commissioner Amy L. Ignatius

Sandy Deno, Clerk

APPEARANCES: **Reptg. Unitil Corporation and Northern Utilities Natural Gas:**
Gary Epler, Esq.

Reptg. Residential Ratepayers:
Kenneth E. Traum, Asst. Consumer Advocate
Office of Consumer Advocate

Reptg. PUC Staff:
Lynn Fabrizio, Esq.
Stephen Frink, Asst. Dir./Gas & Water Div.
Randy Knepper, Dir./Gas Safety Div.
Robert Wyatt, Gas & Water Division

Court Reporter: Steven E. Patnaude, LCR No. 52

I N D E X

P R O C E E D I N G

CHAIRMAN GETZ: Good morning, everyone. We'll open up this hearing in Docket DG 08-048. On October 10, 2008, the Commission issued an order approving the acquisition of Northern Utilities by Unitil Corporation. Among other things, the order provided for a study that would consider how Granite and Northern might be operated and organized for the benefit of customers. The final report was submitted in March of 2010. Subsequent to a review of that report, Staff filed a recommendation in November of 2010 that, among other things, recommended an investigation on a list of issues. We then had a letter filed by the Company asking for an opportunity to convene a status conference to provide an opportunity to make a presentation on the results of the Granite Study. That request was approved on December 10, setting up the status conference that was rescheduled for this morning.

So, this is not an adjudicative proceeding at this juncture. What we'll do today is have a presentation, it appears by numerous people from the Company, and also an opportunity for public comment or for statements from the Consumer Advocate and Staff and questioning from the Commission.

So, with that, Mr. Epler.

MR. EPLER: Yes. Thank you. Good morning, Mr. Chairman and Commissioners. My name is Gary Epler. I'm the attorney for Northern Utilities. We have today, as you indicated, a presentation for the Commission. What I'd like to do is have the panel members introduce themselves and give you their position within the Company. Would you like them sworn?

CHAIRMAN GETZ: I don't think it's -- it's a status conference, I don't think it's necessary to be sworn. So, --

MR. EPLER: Okay. Is that -- does any --

MS. FABRIZIO: No objection.

MR. EPLER: -- party feel differently? Okay. Okay. Then, Mr. Meissner, if you would just start out, just to introduce yourself, your name and your position with the Company, and then the rest of the panel can follow.

MR. MEISSNER: Yes. Good morning. My name is Tom Meissner. And, I'm Senior Vice President and Chief Operating Officer of Unitil Corporation.

MR. FURINO: Good morning. Rob Furino, Director of Energy Contracts.

MR. STEPHENS: Jim Stephens, from Concentric Energy Advisors.

MR. SIMPSON: Jim Simpson, from the Concentric Energy Advisors.

MR. SPRAGUE: I'm Kevin Sprague. I'm the Director of Engineering for Unitil.

MR. BICKFORD: I'm Tim Bickford. I'm the Manager of Gas Engineering for Unitil.

MR. LEBLANC: Chris LeBlanc. I'm the Director of Gas Operations for Unitil.

MR. PFISTER: Good morning. I'm Jonathan Pfister. I'm the Manager of Gas Systems Operations for Unitil.

MR. COLLIN: Mark Collin. I'm the Chief Financial Officer for Unitil Corporation, and I'm the Treasurer of Northern Utilities.

CHAIRMAN GETZ: Good morning, everyone.

MR. EPLER: Mr. Chairman, first of all, I'd like to thank the Commission for giving us the opportunity to provide this presentation. There's a lot of material that we'd like to cover. We'll try to do it in the most economical way possible. We'd also encourage this to be a dialogue. So, if there are particular points, please feel free to interrupt, ask questions, or make comments. And, if it's all right with you, I would ask the same thing of the panel. We have particular slots for people to speak and to make a presentation, but there may be points that one or another member of the panel would like to either add a comment or a point on. And, we ask your indulgence to allow that to happen, so that it is more of a kind of informal dialogue, if that's okay with you?

CHAIRMAN GETZ: That's fine, as long as one person speaks at a time and Mr. Patnaude can record it.

MR. EPLER: Okay. And, yes, well, if I can just underscore that with the panel. Just to speak clearly and slowly, try to speak towards the microphone, and not speak on top of each other. There's also, my understanding is that the Maine Commission Staff members are on the phone line. And, I'm not sure if there's a representative from the Maine Office of Public Advocate as well, but they are listening in to this presentation. They have also been provided a electronic copy of the handout that you have in front of you.

Now, given this is an informal presentation, just procedurally, you do have this binder in front of you. And, we also have a map. Would you like those marked as exhibits in this docket?

CHAIRMAN GETZ: I don't think they really need to be marked as exhibits for identification at this juncture.

MR. EPLER: Okay.

CHAIRMAN GETZ: So, we'll just put them in the docketbook and they will be recorded there.

MR. EPLER: Okay. And, then, we will also be referring to, during the course of the presentation, the Granite Study, which was I think, at least according to the cover letter I have here, physically filed on March 4th, in compliance with the Settlement Stipulation in DG 08-048, and electronic copies were also provided as well. I don't have physical copies of that here, but it is -- it has been part of the docket. And, we'll be referring to items in there, but most of the detail that you'll need for purposes of the presentation is within this binder.

CHAIRMAN GETZ: Thank you.

MR. EPLER: Okay. And, with that, I'll turn it over to the panel, and to Mr. Meissner to begin.

MR. MEISSNER: Good morning. And, thank you for the opportunity here this morning. We do have a fairly large panel. We brought all of the people that have been intimately involved in the study since the beginning, so we should be able to field any questions that arise here today and have the actual technical people that were involved in the study work available for questioning.

The presentation itself is fairly long. We tried to strike a balance, I think, between being comprehensive in covering the different aspects of what the study sought to achieve, but we also tried to not make it overly technical or get into a lot of engineering type, you know, analysis as part of the presentation. So, we hope we struck the right balance. But, if there is questions, we certainly have the people that can answer the questions.

As has been already outlined, as part of the approval docket for Unitil's acquisition of Northern, we agreed to perform this study under Section 7.1 of the Settlement Agreement. The elements of the study itself were set forth in Attachment B to the Settlement Agreement. And, as part of that, we agreed to share our findings, results, recommendations throughout the study process to the other parties and to Staff so that they could provide input, and we had a goal of achieving agreement on the final outcome and recommendations of the study. We believe that we did everything that was requested as part of the Settlement Agreement. I think it's the agreement on the outcome that perhaps is, you know, the subject of this hearing. We will talk more about the study itself further into the presentation and just outline what was actually performed as part of that.

The stated purpose of the study was to assess whether the customers of Northern and Granite would be better served by integrating Northern and Granite. But there was also some more specific reasons behind the study that I wanted to talk about to provide context for the technical work that we'll be discussing. There's going to be a lot of discussion here today about de-rating the pipeline, about changing the pressure of the pipeline, there will be talk about jurisdictional issues. And, so, I just wanted to kind of frame that at the outset, so, when we get to that portion of the discussion, it will be clear why it was an important part of the study itself.

At Page 12 of the Order, Staff outlined one of the concerns underpinning the study, and that was that, in order to comply with new federally mandated pipeline integrity management requirements, Granite has invested approximately seven and a half million and expected to invest another 6.7 million through 2012. That was spending on, you know, integrity management requirements due to its classification as a "transmission pipeline".

The Order then went on to say, "in Staff's view, it is possible that Granite may be able to avoid the expense of the federally mandated pipeline integrity management requirements while still providing safe and reliable service, depending on changes to the corporate structure of Northern and Granite and system engineering. That aspect was really one of the key reasons for the study.

There was a belief among all the parties, including ourselves, I might add, that we might be able to de-rate the pipeline by which we may reduce the operating pressure of the pipeline. And, in doing so, it would no longer be classified as a transmission pipeline under federal safety regulations. If we were to do that, then we would be able to avoid additional spending on integrity management, and those expenditures were outlined as being close to $7 million. So, avoiding that $7 million in additional integrity management costs was one of the reasons for undertaking the study at the time of the docket.

At Page 31 of the Order, Staff also

noted that the safety of Granite's 40 miles of pipeline in New Hampshire and 47 miles of pipeline in Maine is federally regulated. Staff believes, however, that state safety jurisdiction would result in closer scrutiny of pipeline safety. And, Staff is hopeful that issues related to the way in which NiSource has operated Granite and Northern will be resolved by Unitil. This was another element of concerns at the time that led to the study report. There was concerns that Northern, which was being operated by Bay State, and Granite, which was being operated by Columbia Gas, were not being fully transparent in safety regulations and enforcement and disclosure. In particular, the regulatory stations that deliver gas to Northern were owned by Granite, even though they were providing service only to Northern. And, my understanding was at the time, under the prior structure, if questions arose regarding the safety of those regulator stations, Northern could simply point to Columbia, and Columbia would not be responsive to their requests. So, there was a concern around the structure of Granite and Northern, from the standpoint of safety enforcement.

At Page 29 of the Order, Staff testified that, if Unitil's final report finds that customers are best served by Granite as presently configured, and all parties agree, no action by the Commission is required. If the report finds that customers would be benefited from state regulation of Granite, the Commission may be asked to participate in a FERC proceeding requesting state jurisdiction. If other parties or Staff do not agree with the results of the report, the Commission may be asked to open an investigation into what Granite structure is in the public interest.

It then went on to say that the fact that Unitil does not presently operate an interstate pipeline allows for a fresh look at Granite's operation and corporate structure. And, that was one of the final areas of concern identified during the original proceeding, was that the Company did not have experience operating an interstate pipeline at that time. So, I think there was a view that, if the pipeline could be de-rated and removed from its status as a transmission pipeline, that there would be a higher level of comfort with that concern.

So, those three excerpts from the Order I think provide the context for the study itself. The reasons for the study were (1) the transparency of Granite with respect to safety and oversight enforcement; (2) the costs of integrity management, and whether those costs could be avoided; and (3) Unitil's experience managing a transmission interstate pipeline.

I think it's also notable that at that time the report itself tended to be driven by the safety engineers and safety directors of the two Commissions, because much of the concern revolved around safety.

With these as the fundamental concerns behind the study, the focus of the study itself was primarily on achieving a physical or operational change to the pipeline. Meaning, a change to the configuration or the operating pressure of the pipeline, with a goal of trying to remove its status as a federally jurisdictional transmission pipeline. And, in terms of how that might be accomplished, it really comes down to one thing, and that would be pressure. Under Part 192, the federal regulations for natural gas pipelines, a transmission line is defined, in part, as a pipeline that operates at a hoop stress of 20 percent or more of the pipe's Specified Minimum Yield Strength. So, without getting into a lot of technical jargon, the Specified Minimum Yield Strength of the pipe, which you may hear people refer to here as "SMYS", is really a characteristic of the pipe itself. It relates to the size, the materials used, and the pipe itself. So, you can't change that without replacing the pipe.

But the hoop stress, the other part of that equation, is a function of pressure. It relates to the pipe -- the operating pressure within the pipe and the stress that that exerts on the pipe. So, in order to reduce the hoop stress, you would reduce the operating pressure. And, if you could reduce the hoop stress so that it's less than 20 percent of the SMYS, then the pipeline technically is no longer a transmission pipeline. So, that was really the primary goal of a lot of the scenarios analyzed in the report, was to reduce the operating pressure to that level so it falls out of the classification as a transmission pipeline.

I think it's also worth touching on the jurisdictional issues involved, because that will get talked about quite a bit, between state and federal jurisdiction. But there's really two distinct jurisdictional issues involved. One is the ratemaking jurisdiction, which is currently with FERC, but the other is really the safety jurisdiction, and which rules under federal pipeline safety rules are really applicable to Granite. Currently, the applicable rules are those for transmission pipelines, and the enforcement jurisdiction is with PHMSA. So, a goal of the study was, of course, to change it so it's no longer classified as "transmission", which means it would fall under a different set of rules, and the enforcement for those rules would be state jurisdiction. So, the jurisdictional issues are really -- there's two of them; one being for safety and one being for ratemaking purposes.

As we approached the study and scoped the work involved, we were really focused on the second jurisdictional issue, which was the safety jurisdiction. The goal of the study was to change the classification of the pipeline so it was a "distribution" pipeline. That would allow us to change its classification under Part 192.

The ratemaking jurisdiction was really a secondary consideration. In fact, it wasn't really the consideration at all for most of the people doing the study. They were looking primarily at the operational and engineering characteristics of the pipeline.

And, as --

CMSR. IGNATIUS: Mr. Chairman, just quickly. Does that mean then you could end up with a pipeline that is considered distribution under safety standards, but still under FERC ratemaking authority?

MR. EPLER: Yes. That is the case,

because the issue for FERC is whether it's a pipeline, an interstate pipeline engaged in the transportation of gas and interstate commerce. And, if it is, then, under Section 2(6) of the Natural Gas Act, it's subject to the ratemaking and service jurisdiction of the FERC.

CMSR. IGNATIUS: Thank you.

CHAIRMAN GETZ: Well, I'm sorry. Then, the "hoop stress" definition is a Department of Transportation definition then?

MR. MEISSNER: Yes. That's correct. Now, when we agreed to do this study, we ourselves believed that it would probably be feasible to reduce the operating pressure of the pipeline and de-rate the pipeline. At that time, I think everybody sitting here probably thought that was the likely outcome of the report. So, as we -- as we entered the study stage of this, you know, we certainly went in with no bias that there would be any other outcome. I think the people here thought that was the most likely outcome of the study. And, as we talk about the presentation today, you'll keep hearing people referring to "de-rating the pipeline" and "changing the configuration of the pipeline", and, you know, this provides really the context for why de-rating and changing the configuration of the pipeline were an important part of the study objective.

As we turn to Slide 3, in terms of the study itself, Appendix B provided the areas that were to be looked at as part of the study. And, those areas included network planning, which would include system impacts, construction requirements, reliability implication, and the cost of construction under the various alternatives. IMP costs included the capital costs and ongoing maintenance costs associated with Pipeline Integrity Management, and whether we could avoid those costs. Operational impacts included the costs of reducing the operating pressure and splitting the pipeline. Supply contracts included the cost impacts and loss of flexibility in contracting for the supply for Northern and its customers. And, marketers and suppliers recognize the effect on customers, marketers, and suppliers, if the pipeline were integrated into Northern, and whether that integration would affect the availability of the pipeline for wholesale deliveries. And, "legal and regulatory" pertain to exemptions or determinations available, as applicable, to seek a jurisdictional change or decertification under the pipeline under PHMSA.

It's important to point out, I think, that all of these study areas really relate to a change in the physical characteristics or operational configuration of the pipeline, and that's why they were part of the study.

The final paragraph in Appendix B concluded by stating: "Should this study lead to a conclusion that de-rating the pipeline and filing for an exemption from PHMSA regulation and FERC jurisdiction is the most cost-effective long-term solution for Northern and Granite, given due consideration to all the factors I just mentioned, Unitil agrees to file an appropriate plan with the Maine and New Hampshire Public Utilities Commissions and, if consistent with the findings of the Commissions of Maine and New Hampshire, to cooperate in seeking approval of the plan from the federal agencies."

Now, in terms of the conclusions of this study, which I've outlined on Slide 4, our position here today is that the study did not reach such a conclusion. In fact, the study reached the conclusion that the current configuration of the pipeline is really the best configuration for the pipeline and the most effective long-term solution for Northern and Granite and for their customers.

Primarily, one -- one important conclusion is that de-rating the pipeline is not feasible or cost-effective. And, we're going to be covering that in more detail as we go through the presentation. I'm not even sure today if, you know, I don't want to speak for any other parties, but it's not clear to me whether there's any disagreement over that point any longer, that the pipeline cannot be de-rated.

Another conclusion was that the current configuration, as it exists today, is the best configuration. And that, when all factors are considered, including planning costs, operations, management of supply, access for third party suppliers, reliability and safety are considered, there is no scenario that is even closely comparable to its current configuration.

CHAIRMAN GETZ: Mr. Meissner, you said "cannot be de-rated". You mean "should not"?

MR. MEISSNER: Well, I guess maybe "cannot" is maybe too strong a term, because I guess, with money, anything can be accomplished. But it cannot be simply reduced in pressure and operated as it is today from an engineering and planning standpoint. And, to try to do so would require costly upgrades that would greatly exceed the cost of maintaining the current configuration.

CHAIRMAN GETZ: Thank you.

MR. MEISSNER: It would not be able to

essentially serve the existing load at a reduced pressure.

And, finally, the options to split or segment the pipe that we did examine, typically included significant operational and reliability concerns, and we found that all of those alternatives were more expensive than maintaining the pipeline in its current configuration.

Therefore, it's our position today that the current configuration of the pipeline provides the best operational and economic benefits to customers. So, we will be spending a lot more time going through the scenarios, but I think this provides some of the upfront context as we go through it.

And, I did want to note at the outset that there also are some deadlines that we're facing, which I've identified on Slide 4. And, some of those including state work on the Little Bay Bridge between Newington and Dover. You know, we're running up against deadlines on that. And, we also have the deadline of I believe it's December 17th, 2012 to complete all of our integrity management work, including baseline assessments. And, there's a scope of work that goes with each of those that's fairly extensive. And, we already delayed some of that work last year, but we expected to need the next two construction seasons to complete the scope of work associated with those two requirements.

So, that concludes my comments. If there's no questions at this point, I was going to turn it over to Kevin and Tim Bickford to actually provide an overview of the pipeline itself, just to give an operating description of what Granite is and how it operates. And, then, they'll also go through some of the key projects that were talked about in the study, including integrity management, this project, the crossing at Little Bay Bridge, and there was a disbonded pipe project. So, these all became important projects within the study scope. And, Tim will go through each of those individually and just explain what it is.

MR. EPLER: If I could also point out, as Mr. Meissner indicated, initially, the Company was of a view that it could change its operating pressure and perhaps also change regulatory jurisdiction, and that there would be opportunities to do so. And, so, it really went into the study with, if you personalize a company doing this, with an open mind. And, this study, the study that was undertaken, is the process by which the Company made its determination that the current configuration is the best result for customers, for the public. There was

-- and the determination by which the Company has chosen to proceed keeping the jurisdiction with PHMSA and with FERC.

There was no other study undertaken. I mean, there wasn't like a side study that the Company kind of did its own analysis and came to a conclusion, and then just kind of did this because it was required to do it as part of the Settlement Stipulation. This was the process that the Company went through to reach its conclusions.

CHAIRMAN GETZ: Okay.

MR. SPRAGUE: Okay. Please turn to Page 6. I'm going to start by giving an overview of the Granite System, just to make sure that everybody has an understanding of that. And, what I'm going to be doing is, you have an 11 by 17 map in front of you, and that can be used to help orient everyone to the pipeline.

The Granite System consists of 87 miles of primarily 10-inch coated steel pipeline. This pipeline started -- the initial construction was started in the '50s in New Hampshire, and then extended itself up into Maine in the 1960s. The Granite System, as it stands today, not only serves Northern customers, but it also serves marketers and end-users of the system as well.

The configuration of the pipeline, as it stands today, if you look, and I'll use a pointer, this is actually the -- the larger map you see, I'll kind of point out, just so you can look at it on your smaller version. If you look down in the lower corner here [indicating], this is one of the supply points into the Granite System, and that's the Tennessee supply point. In Newington, New Hampshire, which is right about there [indicating], there's a second supply into the system. And, then, up in Westbrook, Maine, which is right near Portland, is the third supply into the system.

So, what we have right now is we have an integrated pipeline, with multiple supply points. It has a great deal of ability and flexibility to serve the load in a reliable manner. It gives -- it gives our gas supply folks the ability to develop the best gas portfolio for the customers, the most cost-effective portfolio for the customers.

And, honestly, I believe, from an engineering standpoint, that if this wasn't an integrated pipeline, that we'd be looking for ways to connect it and to integrate it. And, you know, we might be having a different discussion today, you know, being in front of you asking for, you know, the approval to turn it into the configuration that it is today.

Turning to Page 7, this kind of shows a blown-up view of strictly New Hampshire. And, as I stated before, within New Hampshire, and the little bit that goes into Massachusetts, there's the two supply points; one from Tennessee, and then at Newington, from Portland Natural Gas.

Physically, there's about 39 miles of the Granite pipeline that's located in New Hampshire, and there's less than one mile that stretches over into Haverhill, Mass., to tie into the Tennessee pipeline.

The system, at this point, has 19 regulator stations off of the Granite System, serving approximately 29,000 NU customers within New Hampshire. And, this pipeline operates at a Maximum Allowable Operation Pressure, MAOP, of 492.

If you note on the map that I handed out to you, there are several different highlights that I'll point out. The first being this, kind of the blue line that runs through Stratham. This is the location of the disbonded pipe. And, we'll get into that. I just want to make sure that you have the layout. Just north of that, there's a pink highlight, which is actually used to denote Little Bay Bridge. And, just north of that, there's an orange highlight, where the Granite pipeline actually crosses over the Piscataqua River from New Hampshire into Maine. So, those -- so those will become important as we continue to go through this.

Turning to Page 8, this is -- this is kind of a blowup of the Maine area. If you look at the Maine area, there's approximately 47 miles of Granite pipeline in the Maine system, that stretches from the New Hampshire/Maine border, up to Westbrook, Maine. There's actually a Northern owned and operated line that goes from the Westbrook area, up to the Lewiston/Auburn area.

So, in Maine, there's two primary load pockets. There's, you know, the Greater Portland area and then the Lewiston/Auburn area. In Maine, the Granite System supplies approximately 26,000 Northern customers, and, again, operates at the same operating pressure as it does in New Hampshire.

So, turning over to Page 10 now, entering into this study, as Mr. Meissner had indicated, there were three projects that we needed to address in the near future. And, those are the projects that we worked into the study from a configuration standpoint. Those three projects were the Integrity Management compliance -- Integrity Management requirements, the disbonded coating that we needed to address, and also the Little Bay Bridge.

So, I'll start with Integrity Management. In 2003, sticking with Page 10, in 2003, there was a rule promulgated called the "Gas IM Rule". And, what this -- what this rule required was for operators of transmission pipelines to develop an Integrity Management Program. And, what this Integrity Management Program does is provides a framework for risk-based analysis with respect to the pipeline. And, this risk-based analysis is focused on what's called "High Consequence Areas". And, I'll get into what a "High Consequence Area" is and describe that on the next page. The rule further went on to say is, of these High Consequence Areas, you needed to do a baseline assessment of 50 percent of that by 2007. So, if you think of "High Consequence Areas" as "mileage", you have to assess half your mileage of HCAs by 2007, and the other, the remaining half, assess it by the end of 2012.

The way that you -- there's a couple different ways to assess this that PHMSA allows. One being direct assessment. Meaning, you dig up your whole pipe and you look at it. That's not really feasible. The other way to do it is actually what they call "in-line assessment", or what we'll refer to as "pigging", "pigging" stands for "pipeline inspection gauge". So, if you can imagine, it's actually like a little robot that goes and uses gas pressure to move its way through the pipeline. And, as it's going through the pipeline, it's measuring all different characteristics: Wall thickness. Are there dents? Are there gouges? Is there corrosion problems with the pipeline?

So, once you have -- so, once you do this assessment, you might have anomalies that you need to repair. Up until this point, with the work that we've done, we're happy to say that it's very -- we have a very few amount of anomalies that have been found. And, with the remaining three and a half miles that we have left to do, we're only expecting between one and two anomalies. Meaning, you might have a dent in the pipeline from the original construction that's deeper than code allows. So, you would have to cut out that section and replace that section. That would be an example of an anomaly.

By the end of 2012, we'll have approximately 80 percent of the entire length of the Granite pipeline to be -- it will be "piggable", meaning that the pig can go through it. And, what we've done is we've set this up in extremely long runs. For instance, we can launch a pig up in Westbrook, Maine, and actually receive it down in Eliot. And, what that does is it, because it's such a long distance, it allows us to not only assess those areas that are within an HCA, but also those areas that aren't. Because, you know, HCAs can be short or they can be very long. And, you don't want to install the necessary equipment to launch a pig, and then receive the pig in each of these little sections. You'd rather do it over a longer range. So, by the end of -- so, by the end of 2012, the majority of our pipeline will be piggable and will be assessed.

So, what happens, once you do your initial assessment, then every seven years you need to reassess your pipe. You need to run the pig through it again to determine any changes, and those changes are then addressed. So, looking at the -- if you just take a quick look at that table on Page 10, you can see that we have 34 percent of the mileage of HCAs still to do. That relates to about 3,200 feet within Maine and about 16,000 feet within New Hampshire. Up until this point, most of the HCA work was done in Maine, and, actually, most of that was this line that goes between -- no, no. Forget that. Sorry. I got off track.

So, if you turn to the next page, which is Page 11, which shows a picture. And, this is an example of a High Consequence Area. To determine your

High Consequence Areas, your --

CMSR. IGNATIUS: Before you go on, --

MR. SPRAGUE: Okay.

CMSR. IGNATIUS: -- you got lost -- I got lost. The amount assessed on chart -- on Page 10, in New Hampshire alone, is only 9 percent?

MR. SPRAGUE: Up until this -- up until this point, yes. There's only been 9 percent that's been assessed.

CMSR. IGNATIUS: It's a strange chart, because you've got both dates moving --

MR. SPRAGUE: Right. So, --

CMSR. IGNATIUS: -- down the line, and then states different --

MR. SPRAGUE: Right.

(Multiple parties speaking at the same time.)

CMSR. IGNATIUS: States identified also in different columns, and I can't put it together.

MR. SPRAGUE: Right. Okay. So, between the years 2003 and 2005, there was a little less than 5,000 feet of HCAs that were assessed. That's 9 percent of the total, and all of that was in New Hampshire.

CMSR. IGNATIUS: Oh. Not 9 percent of

the New Hampshire portion?

MR. SPRAGUE: No. Nine percent of the total. From 2006 to 2007, there was about 32,000 feet that was assessed, which is 57 percent of the total, that was all in Maine. So, for the remaining two construction seasons that we have -- well, essentially, this is going to be 2010 to 2012, this is the chart that comes out of the study, but there's a little over 19,000 feet remaining, of which 3,200 feet of that is in Maine and 16,000 feet of that is in New Hampshire.

CMSR. IGNATIUS: Thank you.

MR. EPLER: Kevin, can you confirm a point? Is it correct that, because of the current configuration of the pipe, being a continuous pipe, that the Company can undertake this assessment, undertake the pigging, without taking customers out of service, without loss of service?

MR. SPRAGUE: That is true.

MR. EPLER: Okay. And, that becomes an important point later on in our discussion?

MR. SPRAGUE: Correct.

MR. EPLER: Okay. Thank you.

CHAIRMAN GETZ: Can we get back to the numbers about what's assessed?

MR. SPRAGUE: Yes.

CHAIRMAN GETZ: So, 16,000 feet in New Hampshire of total pipeline that needs to be assessed or HCA area pipeline that needs to be assessed?

MR. SPRAGUE: There's 16,000 feet of High Consequence Areas that need to be assessed.

CHAIRMAN GETZ: So, basically, 5,000 of the 21,000 relevant feet have been assessed. And -- okay.

MR. SPRAGUE: Right.

MR. MEISSNER: To that point, Kevin, just to clarify, though, under our current plan, without regard to HCAs, how much of our total pipeline in New Hampshire will be assessed by the time we're done? Is it most of it?

MR. SPRAGUE: It's most of it. By the time we're done with our Integrity Management Plan, it will essentially be all the way from the -- from the supply point down in Haverhill, all -- pretty much all the way up to Portsmouth.

MR. MEISSNER: So, while the requirement is to do only the HCAs, by doing these long runs, we'll actually be assessing all the pipeline, whether it's in an HCA or not.

MR. SPRAGUE: So, turning to Page 11,

this is kind of an overhead view to explain what an HCA is. The red line that you see coming from the upper right-hand corner, is hitting the road, it turns yellow, and then keeps going down to the bottom middle of the picture, and then turns red again. Essentially, the way you determine an HCA is you take a distance from the pipeline on either side, and that -- and you bring that all the way down the pipeline. And, as you hit areas that have -- it's essentially based upon size of building and number of buildings. So, if you're running the pipeline and it's going through a field, it's not a High Consequence Area. But, in this situation, you get to a large building, which is a factory, that has a lot of people working at it, the consequence of that area is much higher. So, that becomes a "High Consequence Area". So that those are the types of areas that you need to assess. And, as you can see, they can be rather short. But our approach is, as we've stated, is to expand, you know, and assess in between these HCAs.

CMSR. BELOW: And, about what is that distance?

MR. SPRAGUE: This distance right here? This distance is probably --

CMSR. BELOW: No, not the length of this

pipe, the distance on either side of the pipe, if you get within a factory with 20 or more people? What's the corridor, if you will, to measure, to determine whether it's an HCA?

MR. SPRAGUE: I forgot off the top of my head.

MR. LEBLANC: It's 660 feet.

MR. SPRAGUE: That's right. And, that's specified in the Code, in the DOT Code.

CHAIRMAN GETZ: Let me just make sure I got the proportion of these numbers straight. So, there's 38 miles approximately of pipeline in New Hampshire?

MR. SPRAGUE: Approximately, yes.

CHAIRMAN GETZ: So, about 5 miles of that would be HCA?

MR. SPRAGUE: Correct. Okay. Turning to Page 12, this is just a picture to give you some idea. So, when we talk about the Integrity Management Plan in an IMP project, this pipeline was originally installed back in the 1960s. And, when pipelines were installed at that point in time, they weren't -- they didn't necessarily have the eye towards running a mechanical robot through it to measure the inside of it. So, in order to do that, and in order for the pig to be able to fit through, we need to go through and replace any valves or any fittings that might be in the pipe that won't allow the pig to get through.

In addition to that, we have to -- we have to install what's considered a "launcher" and a "receiver". So, you put the pig in one spot. It travels along with the flow of the gas, and then it ultimately comes out another spot. So, these -- that's what an IMP project would look like. And, this would be over, you know, a rather long distance.

Then, what the pig does is the pig, as described, provides a whole lot of data. The pig always knows where it is. It measures, if it finds an anomaly, it knows exactly where it is. So, then, you go back -- then that data is analyzed and says, "okay, you have one anomaly." You go back and it tells you exactly where it is. You dig up that section and replace that anomaly.

Turning to Page 13, the next project, so that was the -- IMP is the first project. The next project that we'll talk about is disbonded coating. And, this disbonded coating, this was originally identified by NiSource, and then has since been verified by Unitil, as we've done with most of the things that they've told us. And, this is this section that runs through Stratham, starts kind of at the Stratham/Exeter border, goes through Stratham, up into the Greenland area, which is the blue highlight on your map. And, "disbonded coating" is just that. The pipes that are -- the transmission pipes that are installed in the ground are steel, but they have a coating over them to help protect them from corrosion over time. And, once that -- once that coating starts to fail for various different reasons, you can't or you can no longer achieve proper corrosion control for that. You can't protect that pipe anymore. So, it's at more risk for corrosion.

And, this could be caused by several different things. It could have been improper installation at the time of the coating. Normally, what you would do is you would buy the pipe from the factory, which has the coating applied in a controlled setting on a nice brand-new, clean piece of pipe. This section of pipe, when it was installed, was actually installed as bare steel pipe, and then the coating applied in the field. So, once you remove the -- once you remove that controlled environment for installing that pipe -- or, the coating over the pipe, it -- you insert a lot of other problems or future problems. You know, with the coating adhering to the surface or, you know, over time just breaking down. And, once that -- once it actually separates itself from the pipe, it creates a pocket in there, moisture gets in and further corrodes the pipe.

So, there's several different alternatives for this pipe. You could replace it, which is what we've proposed to do. You could reapply the coating in the field. But, we, in analyzing this, we ruled it out as being way too expensive. You have to expose the whole pipeline, clean the whole pipeline, now you're trying to apply a coating to a pipe that already has corrosion started. So, it's not a good situation and manufacturers don't recommend that. Usually, in the field, you might apply a coating over a shorter section that you can control a little bit more.

And, another alternative was to remove it from service. So, you'll see that in some of the scenarios that we're going to talk about later. So, you can imagine, if this pipe, this section of pipe was no longer in service, then you would essentially be serving this whole southern area, from the Massachusetts border up through and serving the towns of Exeter, Hampton Falls, East Kingston, and Seabrook, this whole area, which is approximately 12,000 customers, from a single supply point.

The third project that we have is the Little Bay Bridge Project, which is the pink, the pink highlight on your map. Right now, the pipeline is actually suspended from the existing Little Bay Bridge. And, it's on the -- what I'll call the "inside" of that. DOT has come to us a couple years ago and said, you know, "We're doing this project. There are several different options." You can -- you can't leave it where it is, because we wouldn't be able to maintain it, because it's actually going to end up in the middle of the two bridges, just the way it's going to be constructed. So, we couldn't leave it where it is. So, we could relocate it to the new bridge, once that new bridge was installed. You could abandon it, again, like abandoning the disbonded coating, you could abandon it, and essentially segment the pipeline again, so you would have, you know, the one supply for that area. Or, you can directional drill it underneath the bay, which is -- which is the direction that we've decided to go.

We hired an external consultant that actually did the study for us to determine which is the most cost-effective solution. And, it essentially came down to relocating it to the new bridge, abandoning it, or directional drill. The problem with relocating it to the new bridge is that you have to inspect it four times a year. And, I'm sure that some of you know that area, but the Little Bay, in that area, going underneath that bridge has some of the strongest currents of anywhere in New Hampshire. So, it's not necessarily safe for our guys to be out there on a boat, trying to look up, you know, 50 or 60 feet at a pipeline. And, it's not -- and, every three years you have to do a close visual inspection of it, which means you have to be up close enough to actually see the pipe, touch the pipe, and look for any problems.

The directional drill not only allows us to maintain the integrity of the pipeline, but also, in the long run, ends up being the most cost-effective solution, as opposed to, say, abandoning it and installing a gate station in Maine, which has a bunch of different risks.

And, all of this will be discussed as we go forward. And, we believe, I mean, we're confident in the numbers we've provided for this project, because several years ago Maritimes & Northeast came through with their pipeline. Which is a 30-inch pipeline, compared to the, you know, compared to the 16-inch hole that we'd be drilling, they came in with a 30-inch hole, and bored under the river in that same general vicinity. And, we actually got our prices from the same contractor. So, we believe that the risk of the bore is rather low at this point.

CMSR. IGNATIUS: Mr. Sprague?

MR. SPRAGUE: Yes.

CMSR. IGNATIUS: Have you had preliminary or more extensive discussions with environmental regulators about the possibility of doing the directional drilling underwater?

MR. SPRAGUE: We've started that. And, right now, there's no -- there's no "push-back" at this point, we'll say. We don't have the permits, but we've started those discussions.

CMSR. IGNATIUS: Thank you.

MR. SPRAGUE: The next page, on Page 15, you can kind of see, the left-hand picture is what it looks like now. The bridge on the left is the existing Little Bay Bridge. The little bridge on the right is the older bridge, the existing bridge that's now a footpath. And, you can see where the red shows where our pipeline goes. On the right-hand side, you can see they're essentially going to duplicate what they have and make it essentially four lanes in both directions. Keeping that, the older bridge there, as a footbridge. And, you can see kind of the angle of the bore at this point. I believe it's a 2,500 foot bore that we're proposing.

Turning to Page 16 kind of summarizes these three projects. And, there's been, you know, a couple different cost estimates that were provided. And, we just want to clarify those. There was -- there was originally some cost estimates that were provided as part of the Granite State Study. Those estimates were higher level engineering type estimates that didn't have the design work behind them. They're more of a budgetary type of work. And, also within the study, those were unloaded estimates. There were no overheads applied to those.

The current estimates, now we've had another year or so, since these Granite -- since the study estimates were done, to actually do some engineering and to get some more firm quotes and, ultimately, more accurate estimates. So, you can see, from an unloaded standpoint, what we're -- what we have for estimates now are a little less than $500,000 different from where we were when the study was filed. And, what we've done is we've tried to, in order to support the financial analysis, which has happened, we've also provided fully loaded estimates. So, those would be loaded with the non-direct costs associated with the project.

And, in all of the analysis now going forward, the spending that we've done on Little Bay in 2010 was just a little bit to relocate the pipe away from one of the bridge abutments. It's considered "sunk costs", and so those have been removed from the analysis, under all scenarios.

MR. EPLER: If I can just interrupt for a moment. This is -- this review of the cost estimates is important, particularly in light of the Staff memorandum requesting an investigation. Because, if you look at the second page, under the issues, the first concern outlined by Staff was that "the capital investments for which Granite has requested FERC approval to recover through a capital cost surcharge significantly larger than what was stated in the Granite Study." And, I think this chart shows that that's not the case. That the cost that we requested in the rate case were well within the estimates that we use as the basis of the study.

CHAIRMAN GETZ: But how does that -- there's the question I think in the -- that Staff raises about the -- on Page 26 of the Final Report, about the $4.75 million that's not included in the financial model analysis. How does that play out in that?

MR. EPLER: With that, someone might be

able to discuss this in more depth, but what that was was that's the disbonded pipe, the cost that was estimated to replace the disbonded pipe. Now, in doing the study, that cost was assumed for all the scenarios that were looked at.

CHAIRMAN GETZ: All the scenarios or the three that were --

MR. EPLER: For all the scenarios. Because it was assumed that that needed to occur for all -- that, in every scenario we looked at, and we'll get into the matrix of the studies that we looked at, we assumed in each one we would be replacing the disbonded pipe. And, so, since that cost was the same in all studies, it wasn't included in the study, because each scenario would involve that. What Staff requested us to do, subsequent to the study, most recently was to look at not replacing that disbonded section, and to actually cut the pipe up into several sections, three sections. When you do that, since you're not replacing the disbonded pipe, you're avoiding that $4.7 million cost. So, then, to compare that scenario, that new scenario, with the old scenarios, you had to then add the $4.7 million into the old scenarios. So, we had to do those runs over to take that into account.

The Staff asked us, in the initial discovery request in that, and we provided an initial response to that, but we did neglect, in doing that initial response, we did neglect to put that additional cost in. And, so, we reran the studies, to include that cost in our Baseline Scenarios.

CHAIRMAN GETZ: Okay.

MR. SPRAGUE: So that --

MR. MEISSNER: I was going to say, it's probably worth mentioning that the reason we're so focused on the projects is really, I think, the purpose of much of the study was to avoid undertaking one of more of these projects. So, if we avoid integrity management, then that has a savings associated with it. If we avoid the disbonded pipe replacement or the Little Bay Bridge replacement, there was a savings associated with it. So, much of the goal of the study was to avoid the cost associated with these projects in various ways. And, for Little Bay Bridge and the disbonded pipe, the goal was to actually just abandon those sections, so they don't exist anymore or they're not part of the pipeline anymore.

So, that's why I think we're spending a lot of time on the specific projects, because most of the scenarios were designed to avoid these projects. And, that's how the scenarios themselves were developed.

MR. EPLER: And, then, the overlay to that is, if you avoid those projects, do you also change the configuration of the pipeline, such that you're either no longer subject to PHMSA, to the safety jurisdiction, because you changed from transmission pressure to distribution pressure, or have you somehow changed the configuration of the pipeline so that you're no longer an interstate pipeline flowing gas through interstate and subject to the jurisdiction of the FERC. So, you're kind of doing both things. You're looking to avoid costs, avoid projects, and you're looking to see, if, in doing that, and still being able to provide service, you can also change your configuration somehow and change your jurisdiction.

MR. SPRAGUE: So, now, I'll pass it along to Mr. Stephens, who will discuss our approach to the study.

MR. STEPHENS: Thank you, Kevin. So, we're on Slide 18.

(Court reporter interruption.)

MR. STEPHENS: Thanks, Kevin. We're on Slide 18. And, this section is going to talk about the Granite State Study. We're going to go over the goal of the study, the process that was utilized, some of the actual work product, some interim work product that was circulated and discussed with the engineering teams. And, in addition, we're going to discuss some of the post study work product that's just been mentioned, some of the studies that included taking out a certain section of the pipeline and compare --

(Court reporter interruption.)

CHAIRMAN GETZ: You may need to get closer to the microphone.

MR. STEPHENS: So, in addition to walking through the study, we're also going to talk about some of post study analysis that was conducted, and that's going to include some of the scenarios of the disbonded pipeline being removed and compared to the Baseline Scenario.

MR. EPLER: And, if I can just interject, just to give it context, the Company hired Concentric to help us coordinate the project overall, and to help us with financial analyses. All the engineering work was done, however, in-house by Northern or Unitil personnel.

MR. STEPHENS: On Slide 19, Tom has basically talked to most of these points, so I think I'll spend just a short amount of time here, and focus on the bottom of the slide, which is the issues that we had identified to be analyzed, which included the reduction in pressure; reconfiguring the pipeline, either at Little Bay Bridge or at the state border; and we also looked at implications associated with gas supply, marketers, and also on regulatory issues.

I should mention here that we also tried to have a process of a collaborative nature. Now -- and, actually, let me go look at the next slide, which is Slide 20. And, this will focus on the process that we used for the study, and I did this through a timeline.

So, the Commission order established December 1st as the deadline for submission of the Granite State report. However, there were two extensions that were filed for and approved. And, so, one allowed us to extend to January 11th. And, then, the second extension, the Maine Public Utilities Commission set the deadline as February 26, 2010. And, I should say that, in terms of extensions, we, as with everything in this project, it was a collaborative approach. Each of the stakeholders were able to have an approach where everybody agreed to the extensions.

In terms of the timeline, we spent some

time preparing, and we had our first all party meeting on May 29th of 2009. And, then, we had approximately ten meetings during the course of the project. These were either all party meetings or they were engineering only meetings. And, on -- it says here on February 26th we submitted the report, but it might have been March 4th, there may have been a electronic submission versus a physical submission. But the report was submitted on or about February 26, 2010.

And, I should mention one other date that's not here. Is that, prior to having a meeting on February 9th, in which all the parties came to Unitil and we did a page-turn of the report, we sent the report out on January 14th, 2010, so that we could have feedback and everybody had a chance to look at the report prior to coming to the Unitil office on February 9th to do a page-turn of that report.

In terms of participants, the number of people, both from the stakeholder community and from Unitil that worked on this project was pretty significant. From the Unitil perspective, there were at least eight departments that focused on this project or touched it at one point or another. Approximately 20 people from Unitil worked on this project or some portion of this project.

In addition, there was significant time invested by stakeholders. We had engineering meetings that were held in Portsmouth that were fairly long and detailed, and we had very good participation from engineering staff. And, so, it was a very collaborative process. And, at that point, we had also provided the materials ahead of time. We put up a website, so materials would available for all the stakeholders. We also had communication via e-mail. And, there were some telephone communication as well. And, we also sent some very thick materials via FedEx that couldn't be e-mailed, so we also got distributed a lot of engineering studies through the mail.

And, as I mentioned before, this resulted in a submission of the report around February 26th. And, then, subsequent to that, there's been some additional analysis associated with new studies and suggestions from Staff. And, what we're going to do in this upcoming section is we're going to review the results of the study, but also results of the post study analysis that's been conducted by Unitil. And, so, we tried to combine not just the study information, but also tried to address the activities that happened post submission of that study.

MR. EPLER: Also, just procedurally,

just to point out, at the very end, right before filing the report, we had actually discussed with the parties a third extension of time. And, I prepared papers to file seeking an additional extension. And, the Maine Commission indicated that they wanted the Company to go ahead and file the report. I then went back to the New Hampshire Staff and indicated that we could continue, to New Hampshire and asked if they wanted an extension, and was told to go ahead and file the Final Report. So, the Final Report was filed. And, basically, there were no comments received or no correspondence, until after, on this issue, on the issue of the report from any party, either in New Hampshire or in Maine, until we became involved in the rate case, the Granite State rate case at the FERC.

MR. STEPHENS: So, with that, I'm going to turn it over to Tim, who is going to walk through some of the detailed engineering analysis that was conducted as part of the Study.

MR. BICKFORD: Thank you, Jim. I'm going to begin on Page 23. And, before we -- before I get into the scenarios and the results, I'd like to talk a little bit about the process, the engineering analysis process and some of the things that were considered.

First of all, when you do an analysis like this, and you're breaking a system, such as this integrated Granite System, into, you know, all these different segments and you have all these different scenarios, there are many things to consider. Some of them, for instance, do you need new pressure regulator station facilities? Do you need new gate stations? Do you need new pipeline replacements? Do you have to -- what sections of the pipeline can be abandoned? And, what types of technology, for example, horizontal directional drill type techniques can be used to make some of these -- to facilitate some of these scenarios?

In addition, one of the biggest -- one of the concerns that you have, and one of the things you have to look at when you break this system up is system reliability. Right now, as was mentioned earlier, there's a lot of reliability. We have several -- we have three gate stations that serve this system. If you start, you know, breaking this system up into different segments with one-way feeds, you'll lose that reliability. So, our engineering staff had to consider that in these analyses. Whether, you know, decrease some reliability, increase risk and interruption of service. Whereas, today, if you had some sort of a repair to make on the pipeline, you have a secondary feed that you can sustain your customers with. In some of these scenarios that we analyzed, you lost that secondary feed. So, there's future or additional cost considerations, if you have to -- if you have to interrupt service with a segmented system. So, those types of things were looked at in our approach.

CMSR. BELOW: Is there a way that you value that? I mean, certainly, there's a lot of systems, for instance, Manchester, Concord, Laconia, that are served with a single lateral that doesn't have that kind of redundancy. Obviously, redundancy is nice, but how did you -- how did you value that?

MR. BICKFORD: I mean, we place a very high value on it. I mean, as it is today, we, as was mentioned earlier, when Kevin was talking about, for example, pigging the pipeline, we have the luxury of being able to have a secondary feed so that, you know, if we have an anomaly, we can -- we can address that without shutting the pipeline down.

MR. MEISSNER: If I may just clarify, Commissioner, though. In terms of the financial analysis, I don't believe we did value those things.

MR. BICKFORD: That's right.

MR. MEISSNER: They were valued only

qualitatively. So, the financial analysis does not reflect an actual economic value associated with those.

CMSR. BELOW: Okay.

MR. SPRAGUE: But later on in the presentation there are a couple of scenarios with some -- with some estimates for a different configure -- a different configuration would have, say, on portable LNG or emergency response, should something happen. So, we'll get to some of those considerations.

CMSR. BELOW: Okay. Thanks.

MR. BICKFORD: I'm still on Slide 23. So, as far as our approach, we took a -- kind of a start-from-scratch approach. NiSource did have a hydraulic model that we looked at, and we discovered a lot of flaws in that model and didn't feel as though that it would be an appropriate model to use to do this analysis. There were errors such as incorrect pipe sizes, incorrect pipe lengths, inaccurate demands and loads and things of that nature. So, we discarded that model and built our own. We took, you know, a kind of a start-from-scratch approach.

And, so, the process was, the first thing we did was we collected as much of the operating history records and physical attributes of the pipeline as, you know, our records permitted, collected historical flow and pressure data. And, using that information, we developed a new hydraulic model. And, this hydraulic model I will say is very accurate. We were able to calibrate it on two different -- two different test cases, and the model proved to be accurate within 5 percent of field results, which is actually better than industry standards.

In addition to the hydraulic analysis, we also had to do an analysis of all the physical pipeline components and materials, so that we could make the determination, when we were running through these various distribution/transmission scenarios that we could determine, you know, what segments of the pipeline had to be lowered under this 20 percent of SMYS level that was talked about earlier. So, we had to analyze, you know, every segment of the pipeline. Unfortunately, over the years has had several segments replaced, so it's not really one continuous length and diameter of one particular type of material and size. So, there's a lot of components that had to be analyzed.

In addition to that, we also looked at, you know, what future municipal projects would have a major impact on the pipeline. And, as was pointed out, the Little Bay Bridge was a significant project that was identified.

Lastly, the -- I guess that's it. Sorry. Well, I guess, lastly, we took that -- we did the analysis. But, before we get to the results, there's a matrix on Page 24 that kind of shows the different groupings that we did analysis for. For example, Group 1 is also all transmission pressure. The way that -- sort of the way the pressures that we have today. Either integrated as it is today, separated at the Maine/New Hampshire border, or separated at the Little Bay Bridge. So, Group 1 is staying at the same pressure with those different scenarios. Group 2 is -- was a distribution system pressure scenario, where we lowered the pressure so that all segments of the pipeline operated at 20 percent of that SMYS level or less. Then, finally, we did a series of analysis that was a hybrid, which was a combination of the two. We would have, for example, some studies would have, you know, one segment of the system operating at transmission and another segment operating at distribution.

MR. EPLER: If I could just comment here. When you're looking at these various scenarios that we looked at, for example, the separation at the New

Hampshire/Maine border, and the reason that was looked at is to determine whether or not we can actually change it from an interstate pipeline. Avoiding the small section that, for now, that goes into Massachusetts, but basically to separate the pipeline at the border and not having an interstate pipeline, basically have two state --

CHAIRMAN GETZ: So, that's what I wanted to understand. On the right side, for "integrated", "separated at the border", "separated at Little Bay", integrated is the way it currently is?

MR. EPLER: Yes.

CHAIRMAN GETZ: Separated at the border would be purely a legal issue?

MR. EPLER: Yes. It would be a legal issue, but the question is "can you operate the pipeline?"

CHAIRMAN GETZ: But in terms of the scenario?

MR. EPLER: Yes, in terms of the scenario.

CHAIRMAN GETZ: And, then, separated --

MR. EPLER: And, the reason to do that would be solely to avoid FERC jurisdiction.

CHAIRMAN GETZ: And "separated at Little Bay" was more a physical issue?

MR. EPLER: Yes. Yes. To determine there if you could avoid the bridge crossing.

MR. MEISSNER: Just to clarify, though, because I'm not sure if I heard the right thing. Separating at the New Hampshire/Maine border was studied as a physical issue.

CHAIRMAN GETZ: Well, I mean, you do it physically, but to achieve the legal benefit of --

MR. MEISSNER: Correct.

CHAIRMAN GETZ: -- of being exempt from FERC jurisdiction.

MR. MEISSNER: Correct.

CHAIRMAN GETZ: So, that was the impetus for that. Where the impetus for the Little Bay separation is the physical cost that the bridge is going to change and you have to do something?

MR. MEISSNER: Correct. Yes.

MR. BICKFORD: I'm still on Slide 24. In addition to -- I'm sorry, 25. Some of the additional engineering tasks included engineering cost estimates for abandoned sections of pipeline, new gate stations and the different scenarios. We have new ball valve regulator additions, which basically means we'd have to add, in many of these scenarios, additional pressure regulating stations that are a little more complex than the normal typical station. We -- just an engineering term, ball valve regulator stations. The pipeline replacement costs, you know, replacing disbonded or, in some scenarios, we actually had to replace, to make a certain segment distribution class, we actually had to replace the pipeline, so the cost estimates were developed for that, and the Little Bay Bridge crossing costs. In addition, there's costs associated with pipeline integrity.

And, one other thing, we also looked at system growth for these scenarios. We would, you know, we would not only segment the system, let's say, for example, into three different segments, we would look at that, you know, from an engineering perspective, "can it be done?" And, then, secondly, "how much load or how much growth could that area accommodate?" And, we often did that to the point what we call where "system instability" begins. We would take a segmented system and grow it until you started to have a problem, then we would stop and say "the difference between those two scenarios is the potential growth."

And, finally, there's the replacement of the disbonded pipeline. Again, it wasn't really until the latest round of requests that that segment was looked at as a possibility of being abandoned.

On Slide 26, this matrix summarizes the different scenarios that were run. So, for example, if you're looking at a all-transmission scenario, where everything operates at transmission pressure and, for example, if you were to split it at the border, just draw a line horizontally across, horizontally down, and that will tell you the cost to achieve that operational scenario. In addition, in some cases -- well, it also shows you the growth, the growth potential, for those scenarios. And, the ones highlighted in blue ended up being the most cost-effective.

MR. FURINO: And, these are all, Tim, these are all in millions of dollars, right?

MR. BICKFORD: That's correct. Sorry. But I will say again, these scenarios do -- a lot of them reduce our reliability, comes to, you know, right now we have the luxury of having those three supplies, and we have the luxury of being able to shut our pipeline down. And, we'll talk in a little bit here about, you know, planned and emergency shutdowns for a segmented system, and what types of, you know, things are involved and the costs that are involved in accomplishing that. Versus today, where you can segment the system and shut down a segment and still have a supply.

MR. MEISSNER: But, Tim, just to confirm what we said earlier, those were not valued in this financial analysis, correct?

MR. BICKFORD: Not at all. Not at all. And, I'd like to make one more comment. We did a lot of our growth scenarios, and I mentioned we -- we would take the system to the point of where instability begins. And, that's something that, you know, we had to draw a line somewhere to have a benchmark on how to judge growth and be consistent with it. But that is something that we would not want to do. We would not want to grow a system to that point where instability begins. So, it's a little bit of -- you know, that should be considered, you know.

CMSR. BELOW: So, just -- could you explain a little bit more about the growth on this chart on Page 26?

MR. BICKFORD: Sure. Sure. Which, any particular scenario that --

CMSR. BELOW: Well, take "Integrated Transmission".

MR. BICKFORD: Uh-huh.

CMSR. BELOW: You've got Baseline 1 and 2, two costs, two growths. Does that mean that, under the higher cost 3.4 million cost scenario, you have room for 40 percent growth?

MR. BICKFORD: What that is is the first -- one of them is operating at normal pressures; the other one is operating the system at its Maximum Allowable Operating Pressure. So, normally would operate at a normal pressure, I'm going to say, of 375 to 400. But, if you were to take it up to the highest or the Maximum Allowable Operating Pressure, you have more available capacity. So, that's the difference between the two.

CMSR. BELOW: So, I guess I still don't quite get it. Does that mean, operating at the maximum pressure, the Baseline 2, the whole system could accommodate 40 percent growth in load or peak load or --

MR. BICKFORD: If we were operating at our Maximum Allowable Operating Pressure, it could.

CMSR. BELOW: And, then, "Split at the Border" actually allows New Hampshire more growth, but Maine less growth?

MR. BICKFORD: That's correct.

CMSR. BELOW: And, "Split at Little Bay Bridge", now that's a single growth number. What does that mean?

MR. BICKFORD: That's an overall, if you

split it at the Little Bay Bridge, you would have to have a new gate station at Eliot, Maine. So, you would essentially -- you essentially cut the system apart right around in here [indicating]. So, there would be two feeds in Maine and two feeds in New Hampshire that would allow you to grow the entire -- it's a combined number, the entire two states by 70 percent.

CMSR. BELOW: Okay.

MR. MEISSNER: One thing that may be worth clarifying is, in terms of these growth numbers, once you reach one of these thresholds, it doesn't mean that the capacity of the transmission line is completely used up. It's really just the point at which you would have to do some other solution and incur additional cost to add capacity.

MR. BICKFORD: That's right.

MR. MEISSNER: And, for example, if you pursued Baseline 1, which gave you 20 percent growth, and then you reach that threshold, you could theoretically still install the gate station in Eliot, and then take that growth up to 70 percent. So, it doesn't mean that that's an absolute limit on the pipeline. It simply means that's how much growth is available under any of these scenarios without any additional projects to add capacity.

CMSR. BELOW: Until you hit some other constraint?

MR. MEISSNER: Correct.

MR. FURINO: And, in the final evaluation of the various scenarios, there was no -- no credit or attribution for additional growth or no growth, no penalties for, for instance, the 0 percent growth scenario that you get with "hybrid" case and the "Split at the Border" configuration. So, those are all handled qualitatively.

MR. BICKFORD: Yes. Unless anyone has any questions, that completes the "analysis" portion.

CHAIRMAN GETZ: Okay.

MR. FURINO: Okay. Turning to the "supply analysis" section, move to Slide 28. And, I wanted to introduce this by saying that this section of the presentation reviews gas supply impacts and impacts on retail marketers, and specifically how a change in Granite would impact Northern's portfolio.

While the requirements of the study separately listed gas supply costs and impact to marketers, now, these are very much related. On one hand, a portion of Northern's portfolio is assigned to marketers. And, on the other hand, although Northern does not directly supply transportation customers, they are still our customers, and increases to cost to marketers would be passed onto our transportation customers.

I first want to talk about Granite -- about gas supply in terms of the current state of Granite. Northern is the primary shipper on Granite, and also ships or holds capacity on several upstream pipelines, as you can see on the list here. These pipelines deliver the various supplies to Granite. As Kevin and Tim both discussed, Northern can deliver into Granite at the north, the south, and at the middle sections of Granite, corresponding to Westbrook in the north, Haverhill/Pleasant Street, in Massachusetts, of the south, and Newington in the middle.

The current state of Granite allows Northern to serve the aggregate load of the Maine and New Hampshire Division customers using the portfolio on an integrated basis. By virtue of being able to combine the supplies with the redundancy that Kevin and Tim are talking about, the integrated basis provides more value than the sum of the parts, if you will, if we were thinking about trying to supply segmented systems.

The portfolio provides access to numerous supply areas in different parts of the country.

These supplies are delivered to Granite, and are largely interchangeable in their ability to deliver to the different areas that Northern serves. This interchangeability provides redundancy, as we've been saying, which provides security of supply and allows for dispatch optimization. This provides value and reduces costs and risks to customers.

If we turn to Slide 29, this table on Slide 29 lists the firm shippers on Granite. They include both Northern and Bay State, as well as several marketers and an end-user. The shippers other than Northern hold about 20,000 decatherms of firm capacity, or about 20 percent of what Northern holds, which is 100,000. In addition to the listed marketers -- listed customers, several marketers, such as Santa Buckley, Sprague, and Hess, use Granite on an interruptible basis.

Granite receives annual revenue of approximately $1 million annually from parties other than Northern. And, this includes about 700,000 from firm shippers, and about 300,000 from the interruptible shippers. So, that's the current situation with Granite and Northern, and Northern's flexible use of its portfolio.

Turn to Slide 30. As you've heard,

we've studied numerous alternative configurations and pressure scenarios for Granite. The degree to which Granite is reconfigured would serve to undo significant value currently provided to customers from the portfolio because of Northern's ability to interchange volumes along Granite and control flows at multiple receipt locations that it does -- that it has today under the integrated design.

Under various scenarios, the cost to customers include limiting access to favorably priced supplies, lost opportunities to optimize daily dispatch, more challenges and risk in managing balancing agreements with upstream pipelines, and reduced reliability of supply. I think we will be talking about reduced reliability of supply, but it does come at a potentially huge cost in terms of dollars for portable replacement supplies and also for potential loss of service.

And, I think, as Kevin had said earlier, if Granite didn't exist today, we would probably be here with a proposal to construct it, which would allow us to utilize our portfolio in an integrated basis, as we have the opportunity to do now.

If we turn to Slide 31. As I mentioned, cost to marketers will essentially be passed on to our transportation customers. All the marketers, if you think back to the -- look back to the list on the prior page, have Pleasant Street, which is the Massachusetts connection, interconnect, as a receipt point; again, this is on the southern end of Granite and interconnects with Tennessee. Supplies from Tennessee Gas Pipeline are generally less expensive than supplies from the north, for two reasons: New supplies are flowing in to the northern side of Tennessee's system. These include supplies such as Rockies Express and the Marcellus Shale. The other reason, the second reason is that there are significantly more competition in the Tennessee market area than there is on the joint facilities, which is in the north. So, the Tennessee market area has numerous suppliers and competitors and has published index pricing. Whereas, on the north side, there is no published index, and there are very few shippers bringing lots of gas up there. So, it's more of an oligopolistic constrained, less competition type of market.

Restrictions on access to Tennessee would likely cause marketers to restructure their upstream contracts, resulting in increased costs that would be passed on to customers. The same holds true for Northern and would impact sales service customers.

Changes to Granite would also introduce more complex scheduling and retail choice program administration burdens. Taken together, these factors could discourage some marketers from serving our customers. Fewer marketers would mean less competition, and less competition would mean higher costs for our transportation customers. It is worth noting that, while transportation customers include our major employers and institutions that are vital to the communities that we serve.

Unless there are any questions on gas supply, that concludes my comments on that.

CMSR. BELOW: Well, I do have some questions. These are all sort of directional statements. Did you attempt to quantify any of these in any scenarios? Did you try to model what some of these might look like, in terms of dollar value?

MR. FURINO: So, in the course of preparing the study that was filed last February/March, no, there was no quantitative work that actually appears in the study. It's all qualitative. So, while we all get the sense that and we all understand that there would be harm to the value of the portfolio, it's not been quantified and it's not reflected in the cost values that we present. We'll be talking about some of the more recent post study scenarios we looked at. And, we have got some quantitative analysis for gas supply costs in those scenarios.

CMSR. BELOW: Okay. I mean, for instance, in theory, you could at least look at the price separation between the joint facilities supply point and the Tennessee Gas Pipeline supply point over a course of a year, correct?

MR. FURINO: Right. And, that's one of the comments I was making or trying to make. Is that the lack of a published index on the joint facilities makes that a little challenge. There's not the transparency that there is down on the Tennessee system.

CMSR. BELOW: Though, you presumably have had some price quotes yourself, but they're not -- you're saying that it doesn't create a real history?

MR. FURINO: Right. So, we have an operating experience of trying to purchase supplies. And, we do purchase supplies off the joint facilities when it's advantageous to us. But we know from experience that there are very few marketers or suppliers selling gas on the north end, and they know that, and that they're able to extract economic rents as a result of it.

CHAIRMAN GETZ: So, you'll get into this in these post study scenarios a little bit?

MR. MEISSNER: Yes.

(Chairman and Commissioners conferring.)

CHAIRMAN GETZ: I'm just trying to think through the timing. Because I think we're getting close to needing at least a 10 or 15 minute recess, and the alternatives of talking a lunch recess and coming back or taking a short recess and try to get through this. I think we lean toward taking a short recess, perhaps after we get through these scenarios, and before we get into the legal/regulatory considerations and the conclusion. But, gentlemen in the back, I don't know, did you -- were you interested in making a public comment? We could do that.

MR. EMERTON: No, not at this time.

CHAIRMAN GETZ: Okay. Because we'll give you the opportunity at the end of the day. I didn't know if you had --

MR. EMERTON: Okay. Appreciate it.

CHAIRMAN GETZ: Okay.

MR. EMERTON: Thank you.

CHAIRMAN GETZ: All right. Well, then, let's get through the scenarios, we'll take a 10 or 15 minute recess, and then come back to it.

MR. FURINO: Okay. So, to introduce the scenarios, I'll turn it back over to Kevin and Tim.

MR. BICKFORD: Okay. I'm on Slide 33, and this is regarding the post scenarios. We're calling it "15" and "16". And, basically, what this is, is it's -- 15 is keeping the system at transmission pressure, but with abandoning the disbonded segment and abandoning the Little Bay, the Little Bay Bridge crossing. Again, that was -- that's keeping the system at transmission pressure. So, you would have a one-way supply from Haverhill, essentially to Exeter, New Hampshire. The middle segment would be a one-way supply from Newington into the Portsmouth area. And, then, finally, there would be a two-way supply, we would have to add a new gate station on the Eliot, in Eliot, Maine, across the border from New Hampshire, so the Maine segment would be fed from two supply points. Yes. And, in addition to that --

CHAIRMAN GETZ: Just a question about timing. Were these studies done before or after Staff's November 18 filing with the Commission?

MR. BICKFORD: After. I do want to point one thing out. Because the Little Bay Bridge, in Scenario 15, is abandoned, you do have a segment of pipeline in New Hampshire that would be back-fed from

Maine, across the border, and serves approximately 10,000 customers in the Dover/Somersworth area. So, it's important to note that the segmented Maine system would feed back into New Hampshire.

CMSR. IGNATIUS: What's the consequence of that? You make it sound like that's something that would be of concern.

MR. BICKFORD: The consequence -- the consequence is that if -- so, it's essentially a one-way supply, a one-way feed -- this thing's not working anymore -- into the system. There we go. So, it would be -- whereas, today, as I mentioned earlier, we'd have the luxury of having two supplies in that area. It would be a one-way supply back across the border into New Hampshire. And, if we were to find an anomaly or had to do maintenance on the pipeline, on that segment of pipeline, we would have to find a -- we wouldn't have a secondary source, and would probably have to do it with temporary portable LNG, liquefied natural gas systems, and that would be very difficult. I'll get into a little more detail on that.

Scenario 16 is the same, but the only difference being we lowered the pressure in the analysis to distribution. Which cause us to have to replace a lot of segments of the pipelines so that it would operate under the 20 percent of SMYS mark. In addition, you know, several new facilities would have to be installed.

I spoke -- I just spoke about, I'm on Slide 34 now, and we talk about segmenting the system into those three different segments. In two cases, first of all, from Haverhill to Exeter, that would be a one-way feed, as I mentioned earlier. And, if there was to be a shutdown, whether it be planned or unplanned, again, you don't have that secondary supply. You know, we have an example here, I won't skip ahead too much here, but, in the Exeter or on that Haverhill feed, we'd be looking at, you know, a huge -- a huge event, if we had some sort of, you know, repair to make. We'd be talking about 200 mutual assistance crews, for a seven to ten day restoration, could cost as much as $2.5 to $3.5 million just to make the repair.

Again, we have -- today, we have the luxury of being able to sectionalize that. Let's talk about the middle section, it's the same. Newington would feed that one section. And, if you had an interruption in that system, you'd be in the same situation, pretty much the same number of customers. And, I will note that a week ago today we had an emergency shutdown of the

Newington gate station. It was unplanned. It happened very quickly. We lost supply for a couple hours. Luckily, it was -- a supplier was able to make the repairs. But, had that pipeline been segmented, as it is in Scenario 15 or 16, we would have lost that system. We would have lost, you know, approximately 10,000 customers. And, again, as I mentioned earlier, the same is, the line coming back across the border, in the third segmented system from Maine, that would also lose the reliability that we have today.

MR. MEISSNER: In terms of reliability, it's probably worth pointing out that, you know, the types of scenarios that could result in an interruption of service, I mean, we could have a situation or a failure on the pipeline itself, the Granite pipeline. We could have an incident involving the gate station or the regulator station feeding that portion of the system. Or, we could have some sort of incident or supply situation involving supply to our system externally. And, we have had those situations in the past as well that I think Rob could probably speak to.

MR. FURINO: Well, there are, you know, there are different times when pipelines upstream are going to have -- experience conditions on their system that will cause them to post restrictions. And, you know, when they post restrictions, it requires the companies that are shipping on their pipeline to maintain, you know, very strict tolerances with respect to their deliveries and receipts on those upstream pipelines.

So, we had a recent experience with Maritimes, had called and posted a restriction, and Northern had been banking gas with them as part of our OBA, our Operational Balancing Agreement, and had been counting on drawing down those supplies. But they threw up this restriction, without any evidence of what the underlying problem was on their system, and this prevented Northern from using those supplies to satisfy its demands on some of the coldest days.

Now, because we had flexibility on the system, we were able to bring supplies in at other receipt points on Granite and offset that loss of our expected supply.

CMSR. IGNATIUS: Could I ask one other question? Other than the flexibility/reliability issues, are there any safety issues in having a one-way feed that are of concern?

MR. BICKFORD: Well, I think it becomes a safety issue if you were to have, you know, a significant pressure loss. I mean, obviously, I think the things that come along with re-gasification of a system, it depends on how many distribution systems it effects. But, you know, certainly when we have loss in pressure, you know, it's a safety concern, as well as, you know, a concern about losing customers. There's certainly risks involved with low pressure situations.

CMSR. IGNATIUS: Thank you.

MR. EPLER: Yes. If I could, I want to emphasize this issue a bit, because sometimes, in the engineering analysis, it can kind of sound dry. But, in terms of the real consequences of it, it is very significant. The situation that Mr. Bickford mentioned before, in terms of Newington Station, if we had -- if we had an operations where the pipeline was split, and there was only a one-way feed, that would mean total loss to the Portsmouth customers. And, you're talking about then, once you restore that system, you have to go house-by-house to relight those customers. So, and I'm not sure of the exact number of customers we have there, but that's a major undertaking on the part of any company, to go into an urban area and have to relight all your customers. So, that would have occurred if we had a split pipe at, you know, either the border or at the bridge, in that location. I mean, that's not something that's just conjecture out there. So, in any of these scenarios where you're talking about splitting the pipe, and you're going to a one-way feed, you have that possibility, either under an emergency situation or even if you have a planned outage, where your have to take the pipeline out of service. We have the pipeline crossing under the Piscataqua at the border, and that will be mentioned coming up in one of the scenarios. I mean, if it's -- if we have to do certain work on that, for safety purposes, analyze the pipe under the bridge there, and you don't have a Little Bay Bridge crossing, you split it there, then you've only got a one-way feed into the Dover area. You lose service into Dover. Now, the only means of replacing that service would be through the LP gas.

We actually had a situation in Fitchburg two summers ago, where, because of construction work on the pipeline, and that's a one-way feed system, because of construction work on the pipeline, we had to have the entire system supplied by LP. Now, first of all, it was a tremendous engineering undertaking for our company. We had advance notice of this, so we were able to plan for it. In that situation, we actually have locations where we have LP and propane/air facilities. So, we were able to use those facilities and do the planning. But it's an incredibly enormous undertaking. You've got to coordinate trucks going in on a constant basis. Those trucks may or may not be available on an emergency basis. Even in terms of a planned outage, it was a very significant undertaking to reserve those trucks and to reserve those supplies. It was extremely costly. We were, again, through various efforts, we were able to get the pipeline to pick up those costs or a significant of portion of those costs, but that was a several million dollar event.

And, so, when you add the possibility of that cost to any of these scenarios, I mean, it overwhelms the dollars involved. So that the significance should not be downplayed. These are events that we have experience on our system. And, so, the benefit of having an integrated system, with multiple areas that you take gas from, both on supply and operationally, it's a tremendous benefit to the system, and one that you really want to think very, very hard at moving away from. And, we've said this internally to ourselves constantly as we've gone through this study. If we had a bifurcated system, a system that was split or a system that was at low pressure, we would be researching now how to get to an integrated system at the higher pressures, because of all the benefits that we have.

So, a lot of that is sometimes hard to capture in a study. When you're looking at the dollar values, a lot of those qualitative issues are not captured in the dollars. So, I just want to caution, in terms of like when you go back and look at the matrix and you see that some of the dollars look close, they don't capture the qualitative benefit of the system supply and the reliability and the safety that you get from an integrated system.

MR. SPRAGUE: One discussion that we've had with Staff, and it has been brought up today, is that there are radial portions of our Northern system that serve several thousand customers. But, in this situation, or if we are to split the pipeline in several sections, not only do we have those areas, but now we're exposing a larger number of customers to other events that they aren't exposed to now. So, it does have an effect on reducing the reliability of, you know, say, you know, we have a long -- we have a one, you know, a one-way feed that, you know, goes from East Kingston, all the way down into the Seabrook area, that serves about 2,000 customers. You know, that's the only way that those customers are served. If something happens there, we lose 2,000 customers, as it stands today. If something happens, if we split, and, say, abandon the disbonded pipe, and something happens along the Granite portion, that 2,000 becomes 12,000, which magnifies the restoration efforts and the costs that much more.

MR. FURINO: And, Kevin, that's on the Northern system, that isolation?

MR. SPRAGUE: Right.

CHAIRMAN GETZ: So, that would be -- I'm sorry. That would be the area south of the disbonded pipe?

MR. SPRAGUE: Correct.

CMSR. BELOW: So, that's on Page 34. You -- it's more or less the worst case scenario, which is you lose your whole distribution system south of the disbonded pipe segment, because it's just one big radial system. And, so, your estimate of "200 mutual assistance crews", that's mainly for the restoration, going from customer to customer to relight?

MR. SPRAGUE: Correct.

CMSR. BELOW: And, is that -- that's the cost estimate and the time restoration would be your estimate for these 12,000 customers what it would take to restore service, once they lost pressure to the point where you had to relight them?

MR. SPRAGUE: Correct. That's based upon the number of relights that we think an individual technician could do in a given day and the cost of that technician.

CMSR. BELOW: Okay.

MR. MEISSNER: And, I believe the next largest system is the Dover/Rochester system, correct, where we have roughly 10,000 customers?

MR. BICKFORD: 10,000 customers.

MR. MEISSNER: Which, you know, under these scenarios, would be fed radially under the river from Maine, getting back to that discussion. So, the cost and the restoration period for that area would be proportionally similar to this. It would be 10,000 customers, instead of 12,000. So, you know, essentially, 80 percent or more.

MR. EPLER: Also, just to point out, both the Fitchburg, Fitchburg Gas & Electric gas system and the EnergyNorth system, while they have one-way feeds, they also have peaking capability, which helps with pressure drops and pipeline supply issues. We don't have those peaking capabilities here. So, and if you think of adding them, then you're just adding, you know, significant costs, if you go through any of these scenarios where you're splitting pipes, creating one-way feeds, and then you want to add that peaking capability, that's a significant investment, a significant cost. And, you'd have to consider, I mean, do you have a location where you could add that? And, what's the line of acquisition costs? And, what kind of a response you get from a community, without trying to, at this date and time, you're trying to put in a peaking capability where one is not already present.

MR. MEISSNER: Yes, that's a very good point, because it also applies to a comment made earlier with respect to the other gas systems in New Hampshire. I believe the other gas systems in New Hampshire have significant peaking capabilities and on-site production capabilities of both propane and natural gas. And, we do, as well, on Fitchburg. We have a liquefied natural gas plant and we have a liquefied propane plant. So, we're able to inject and deliver a lot of supply into our system outside the pipeline. But, in the Northern system in New Hampshire, that doesn't exist.

MR. FURINO: Yes. And, even leveraging those facilities in Fitchburg during that period which Gary was talking about, when the pipeline service to

Fitchburg was shut down, that was during a three-month period over the course of a summer, Summer of 2009. And, the cost of the vaporization equipment and the trucking itself was approximately $2.3 million for that three-month period. And, that was a period during the summer, when loads were low. And, the customer base in Fitchburg is about 15,000 customers. So, about half of the number of customers in each of the divisions for Northern, in the New Hampshire Division and the Maine Division each with 25, 26 to 29,000 customers. So, that was a significant expense for us, even though we had the facilities that we could use to actually plug those trucks in and have the supply enter the system.

CHAIRMAN GETZ: Okay. Is there more on the Scenarios 15 and 16?

MR. BICKFORD: Sure. If I could start off on Slide 35 please. As Mr. Epler pointed out, we did have a planned event in Fitchburg, and there's a photograph that shows the portable LNG facility in Fitchburg. And, as he also pointed out, we do have a peak shaving plant that's in Fitchburg, on the Fitchburg system, that was also used at the same time. We talk about Scenarios 15 and 16 and reliability, and what would happen if we were to have, say, a planned event where we needed to have one of these portable LNG facilities? And, in most of the systems, there's no place to put it. As you can see from this photograph, it's a pretty big operation. Secondly, the biggest difference between this operation and the photograph, and what we would need on the segmented Granite System, for example, in the Haverhill scenario of a one-way feed, if we were to have a planned interruption, we're looking at a portable LNG system that requires more pressure than something like this can actually put out, there's only one unit in New England that's capable of the pressures that we would need. And, depending on the time of the year that we would need it, it may not even be able to supply the demand. So, that's, you know, a big concern.

MR. FURINO: You know, and, Tim, we say "one unit in New England", but that unit travels throughout the country.

MR. BICKFORD: That's correct.

MR. FURINO: It's not always in New England.

MR. BICKFORD: Yes. It's not in New England right now, I don't believe. And, again, there really is no place to set up an operation like that. A lot of this pipeline, especially in Maine and in southern

New Hampshire, is in the rural areas. You know, and you're talking about setting up an operation that would be bigger than what's in the photograph.

I want to talk a little bit about Scenario 13A, which was one of the most economical scenarios. It was strictly a split at the Little Bay Bridge, with two supplies in New Hampshire. And, so, you would have the disbonded piping would still be in place, it would be replaced. So, we'd have a feed from Haverhill to Newington and Newington back, split at the bridge, and then a new gate station in Eliot, so you'd have two-way supply in Maine. But you're still vulnerable on that leg in New Hampshire that goes back across the border and serve Dover and Somersworth. In addition, we would still be required to do our IMP work. That's still required.

Again, to emphasize on this scenario, the reliability and redundancy that we lose. And, the other thing that I'd like to mention is that, you know, in order to site a gate station and do all that IMP work, and there's also a few other system improvements that would have to be put in place, that we certainly, you know, in the timing of the Little Bay Bridge Project, we certainly don't have a whole lot of time to accomplish this kind of work. It's a very short period of time to do a lot of work, especially the gate station, which requires siting and, you know, it can take quite a long time.

I'm on 37 now. And, I'm going to go over Scenarios 15 and 16. And, just to remind everyone, 15 and 16 are the three segmented systems; one, 15 being at transmission pressure and 16 being at distribution pressure. Again, our concern are the risks associated with losing our redundancy. You know, an emergency event, as mentioned earlier, we estimate could cost as much as $3.5 million to handle, you know, in a seven to ten day period of time. And, even a planned maintenance event, we estimate could be as high as a million dollars. And, again, as I mentioned earlier, the largest portable LNG unit is typically not available, and does require a pretty hefty reservation fee.

Again, you know, I know I've said it a lot, but we have the flexibility now to conduct our pipeline integrity work. We can shut down segments of the pipeline to cut out valves and fittings that are non-piggable. So, we can do that without interruption to our customers.

And, in Scenario 15, for example, where we would still be obligated to do pipeline integrity work, we would really, you know, we'd be in a tough spot. We wouldn't be able to have that flexibility to shut down our system. And, again, the LNG, the portable LNG requirements for pressure are just too high.

Should I touch on ---

CMSR. BELOW: On Page 37, the numbers you have for "increased gas supply cost", are those an annual estimate or example?

MR. FURINO: Yes, that's an annual estimate. The $1 million represents the cost of approximately 10,000 decatherms of Tennessee capacity that would no longer be deliverable to the Granite/Northern combined system, because of the disbonded coating being out of service and the smaller service area that that one area feeds. So, that looked at our least economic Tennessee capacity and release that on a permanent basis, and it assumes some cost mitigation by releasing that and obtaining back value for that, and then also replacing it with capacity on the joint facilities.

And, then, the second piece of that is the higher cost of the two. Being restricted from being able to use Tennessee Gas Pipeline supplies is, you know, we did provide some numbers to Staff and we conducted some analysis on that. And, you know, the supplies in the Tennessee area being brought to our system versus the cost of replacement supplies on the north side of the system of the joint facilities, times the volumes that would be restricted, no longer deliverable from Tennessee, creates this 2.5 million per year. And, that reflects all customers, the sales service customers and also transportation customers.

MR. BICKFORD: One thing I'd like to point out is, as far as take away from Tennessee Gas goes, as it is today, we have a lot of demand in the Dover/Somersworth area that pulls a lot of that gas, you know, from Tennessee. And, you know, we can back off Newington to get more gas from Tennessee. But, in Scenarios 15 and 16, as well as 13A, Dover/Somersworth is isolated and fed from the Maine side, so you can't, you know, you lose that demand. And, that's a big part of --

MR. SPRAGUE: So, where we haven't quantified the gas supply impact of the Scenario 13A, it is an increase over our Baseline Scenario right now, but it's probably less than the Scenario 15 and 16 costs. Just because there is -- you are maintaining, you know, a little bit more load in New Hampshire under Scenario 13A than you would in Scenarios 15 and 16.

CHAIRMAN GETZ: Okay.

MR. EPLER: I also want to underscore an

additional issue with respect to splitting at the Little Bay Bridge. It requires, as has been mentioned, the siting of a new station, Eliot station. And, while we're able to give with some confidence an estimate of doing the horizontal drilling and replacing that piece of pipe that's now on the bridge and going underneath the river, we have a very high degree of confidence in that, in part, because there was a recent project, I believe within the last two years, that also went under the Piscataqua. And, so, we've approached the same company. And, so, under very similar conditions, by the same company, we have an estimate of cost.

For the Eliot station, it's only a rough estimate. I mean, you've got permitting issues, site location. We don't have land there now. So, the estimate of cost is -- we just don't have a lot of confidence in. So, that could be, you know, we could be off on that estimate by a factor, and it's just an unknown. And, also, you just don't know what kind of opposition you may have in terms of siting. I'm sure the Commissioners are very familiar with in other cases before it, siting of facilities in this day and age is a very difficult thing to undertake because of local opposition.

CMSR. BELOW: Well, did you provide an

estimate of that take station cost? I mean, you're referring to it, I'm just not sure I notice the number for it.

MR. EPLER: Yes. We could talk about that in the financial analysis, but I believe our estimate was about two and a half million dollars.

CMSR. BELOW: Okay.

CHAIRMAN GETZ: Speaking of which, the Financial Model Analysis, are we ready for that?

MR. SIMPSON: I'm ready, if you're ready.

CHAIRMAN GETZ: Okay.

MR. SIMPSON: I will get through this quickly. The purpose of the financial analysis is, you've heard throughout this morning talk of the different scenarios that the Company has analyzed. And, each of the scenarios comes with it its own set of capital projects, you know, which translates into plant in service, and also operating expenses. And, for each of the scenarios, these capital projects and these operations expenses have their own set of timings. They don't all occur in the same year, they occur throughout time.

So, the purpose of a financial model is to organize these, the timing of the capital projects for each of the scenarios, and the O&M expenses for each of the -- each of the scenarios. And, we're talking capital and O&M related to the major engineering construction projects, the take station, and the abandonment of the pipe, and similar projects. But, for the integrity management, there is also their own set of capital and spending streams throughout time. And, it's specific to the configuration of the pipe. What is at high pressure? What's at low pressure? How things are integrated or not.

So, the financial model takes all of these into consideration. It expresses the plant in service for each year, for each scenario, plus the operations expenses, in terms of a regulated revenue requirement. And, then, the financial model calculates the net present value of the stream of revenue requirements associated with each of the scenarios. And, in that way, we can do a quantitative comparison of the different scenarios. Which, of course, doesn't get into the qualitative considerations that Tim and Kevin have -- and Rob have talked about.

But I want to draw your attention to Slide 40. That I think, first of all, I can say that this financial model is well vetted. We have shared this model with the Maine Commission -- Maine and New Hampshire

Commission Staffs and the OPA and OCA. And, as a matter of fact, the New Hampshire Commission Staff found a minor bug in one of the formulas. We fixed that. It didn't have any effect on the conclusions, but it was, you know, a good exercise that they went through to, on their own, validate the calculations that we've made. And, we have made, throughout time -- or, from the time that the report was filed in 2010, based on the analysis we had done at that time, we have made updates and revisions to the model. Most of the updates have been for the purpose of putting into effect suggestions and recommendations from the New Hampshire staffs, you know, so that we could consider the new scenarios that they wanted to look at that would avoid having to pay for or to replace the disbonded pipe, for example.

The table at the bottom of Slide 40 is now. This is a summary representation of the results that come out of the financial model. It shows, for each of the five scenarios that are represented in this table, it shows the net present value revenue requirement at two decade intervals, 2020 and 2030. And, then, just for ease of review, it also shows the ranking of those different scenarios for -- at those decade milestones. And, all things taken together, the revenue requirement present valued impact of the integrity management projects and the engineering capital projects, the *status quo* Baseline 1 project is the lowest cost option.

Again, in a way, this quantification does not take into account the safety and reliability considerations. And, also, let me add that, as Rob explained, we have included, in the financial analysis, quantification of the gas supply impacts for the scenario in which the disbonded -- in which the pipeline was abandoned at the disbonded segments. But we have not quantified the gas supply impacts of the scenarios where the pipeline would be split at Little Bay Bridge, so that we could avoid the costs of the Little Bay Bridge crossing.

So, what that means is that the financial model results for Scenario 13A and Scenario 5 on this table are understated, because we have not -- we have not quantified the gas supply impacts for -- associated with those scenarios.

That's all I wanted to say about the financial model.

CMSR. BELOW: Well, just one quick question. Your first bullet on Page 40 says that the Scenarios 15 and 16 "were added", but they're not in the table at the bottom?

MR. SIMPSON: That is correct, because those scenarios are so expensive, they are sort of "off the chart", literally and figuratively. They're very -- all things considered, what has to be done to deal with the implications of Scenarios 15 and 16 is that they are very expensive scenarios, both gas supply and the engineering-related considerations.

CMSR. BELOW: But do you have numbers to support them? I mean, did you run them through the model?

MR. SIMPSON: Absolutely, we did.

CMSR. BELOW: Okay.

MR. SIMPSON: And, I don't have it in front of me right now. But I can tell you that Scenario 15 is at least double the cost of the Baseline Scenario. And, I say "at least", because there are different interpretations between the Company and the Staff as to the gas cost implications. But, at the most conservative way of estimating the gas cost implications, the Scenario 15 is double the cost of the Baseline Scenario.

CMSR. IGNATIUS: But I thought you were making a point that you hadn't included the gas cost repercussions --

MR. SIMPSON: I'm sorry, I wasn't clear.

CMSR. IGNATIUS: -- at 13A and 5, so why are they necessarily included, and the other, being 16 and 15?

MR. SIMPSON: Because those were -- well, I'll start, and maybe Mr. Furino has something to add. That 15 and 16 were new scenarios that were just started to be considered in the last couple of weeks. And, you know, they did get some traction, because there was some -- it did seem slightly logical that, if you could avoid having to replace the disbonded pipe, that that would be a significant cost savings. If you could avoid having to deal with the Little Bay Bridge crossing, that would be a significant capital savings. And, so, then, the question became "Well, what are the other implications of Scenarios 15 and 16? And, do those other implications outweigh the savings that are associated with 15 and 16?" And, the quick answer is, you know, it, on its surface, 15 and 16 looked interesting enough that the full analysis was done, I think is the simple way to say it.

MR. MEISSNER: I mean, I think one of the things that factors in just simply is 15 and 16 I think were studied over the last two to three weeks maybe, and I think 13A is an alternative was raised again only in the last one or two days. And, so, I don't think there was time to actually evaluate the cost of that alternative. It was re-raised, I guess, in the last couple days. So, some of this was just truly last minute, preparing for the presentation.

MR. EPLER: Well, I don't want to give the impression that it wasn't studied. We performed these studies for the initial report. There were no additional questions at the time we submitted the report or after submitting the report. I believe, probably in terms of timing, I guess, as a consequence of some issues that came up as a result of the rate case at FERC for Granite State, the Staff issued its memorandum on November 18th, many months after we finished the report and many months after, you know, our last conversations on these issues. So, we were requested to undertake a new scenario. The Staff, you know, as part of this process that we're here before you, the Staff issued a number of data requests, and, as part of that, basically asked us to undertake a new study.

Internally, in our shop, we didn't think that the new scenario that was requested was a viable one, but we undertook the study nevertheless, and we got the results that it showed. And, in order to demonstrate fully the -- that it wasn't a viable alternative, we had to go and include the gas costs to demonstrate that there were significant issues that would affect gas supply, gas supply costs significantly. And, so, we worked, and we worked in concert with the Staff in developing the estimates of those gas supply costs. So that, when you add them to that scenario, it shows that the cost comparison -- I mean, continuing the integrated analysis, running it as an integrated pipeline as it currently is, is much cheaper than this new scenario that we were asked to run.

Subsequent to that, and we had a conversation with Staff where they acknowledged that, that that scenario was no longer viable. They then --

CHAIRMAN GETZ: That scenario being?

MR. EPLER: The 15 and 16, having three separate, independent segments. Subsequent to that, they indicated that there was still interest in looking at what we've indicated here is Scenario 13A, splitting it at Little Bay Bridge. And, so, we -- but that conversation was, I believe, Wednesday afternoon. And, so, in quickly preparing for this, we went back to that analysis to take a look at it. And, the difficult -- the problems that that scenario presents are those that were pointed out previously, in that you create a one-way feed, and you have those reliability and safety concerns by creating that one-way feed in the Dover/Rochester area. There are -- because it's a split of the pipe, and you can't run it as an integrated system, it also has gas costs, some type of gas supply costs. We didn't do the specific analysis on gas supply costs for that scenario that we had done for 15 and 16, because there simply wasn't enough time. But just the fact that you were splitting the pipe means that it has some impact. It's not an equal comparison. There is some impact on that, so that would have to be factored into the cost of service analysis that's done, that shows you as those two scenarios being relatively close.

CHAIRMAN GETZ: Okay. Let's take about a 15 minute break.

(Whereupon a recess was taken at 12:38 p.m. and the hearing reconvened at 1:00 p.m.)

CHAIRMAN GETZ: Okay. Mr. Epler, I guess we're --

MR. EPLER: Yes.

CHAIRMAN GETZ: Unless there's something more on the financial model, we're up to the legal and regulatory analysis, and I guess, after that, the conclusion. Though, I think we've gotten a head-start on that a couple of times already.

MR. EPLER: Right.

(Laughter.)

MR. EPLER: Well, as we said, for us internally, after doing this study for a while, it did become -- we believe it became obvious. Okay. Well, talking about some of the legal and regulatory considerations, some of this has been mentioned before during different parts of the discussion, so I'll try to go through this quickly, also in the interest of time.

Basically, as was indicated at the outset, Granite State's engaged in the transportation of natural gas and interstate commerce within the meaning of Section 2(6) of the Natural Gas Act, and, therefore, it falls under the regulatory jurisdiction of the Federal Energy Regulatory Commission. And, here I'm going to focus mostly on the FERC jurisdictional issues.

So, what that means is that the rates and terms of service are subject to the FERC, and the corollary to that is that the rates and terms of service are not subject to the jurisdiction of the states. Moreover, the states do not have the authority to order an interstate pipeline to change its jurisdiction. That authority is with the FERC. The FERC would determine whether an interstate pipeline should no longer be subject to its jurisdiction, and it would go through an abandonment process under Section 7(b) of the Natural Gas Act. And, that can be accomplished different ways, either, as we've discussed, by actually reconfiguring the facilities so that they no longer are interstate facilities. There are also a couple of provisions where you -- where the pipeline, even though it has some interstate characteristics, jurisdiction is given over to the states. There is an -- what's called an "area determination", that's Section 7(f). And, there's also a thing that's been commonly referred to as a "Hinshaw" pipeline, where, again, under certain characteristics, even -- again, even though it's an interstate pipeline, jurisdiction over that facility and the gas that's flowing over that facility is given to the states. The FERC looks for different kinds of things, but there are qualifications that you'd have to show in order to meet those criteria.

Should there be a desire to change, that has to be volitional on the part of the interstate pipeline. As I said earlier, that an interstate pipeline subject to FERC cannot be ordered by the states to change its jurisdiction.

And, that's a significant point, because that relates to the Settlement Agreement that the Company signed and where the provision for undertaking the study appears. That Unitil, as the parent company in signing the agreement, did not agree that it would change the jurisdiction, the configuration or the jurisdiction of Granite, with no conditions. It was a conditional agreement to do a study and to determine if there were operational reliability costs and general public interest considerations that would support such a change. And, if those conditions existed, it would then look at the potential of going before the federal agencies and seeking a change in jurisdiction. And, so, at the initial -- at the outset of the study, the Company met with its FERC counsel, and we had an initial, very preliminary analysis done of the alternatives that I mentioned before, the Section 7(f) determination and the Hinshaw possibility. And, essentially, the information that we received is outlined starting at Page 32 of the Granite State report. We just -- we got a very high level analysis from outside FERC counsel, and we really didn't go into detail into the possibilities, because at that point we thought it was very premature, because the driver, based on what's in the Settlement Agreement and what we were looking at, were these operational configuration changes. And, so, after having that, getting that initial information, we then turned the attention of the study to the engineering analysis. And, therefore, once it became very evident to the Company that there were no operational savings or reliability savings or benefits, and, again, you know, looking at the specific criteria that's laid out in that paragraph that I -- that's quoted on Page 42 of the handout, the consideration of planning, costs, operations, management of supply, access for third party suppliers, reliability, safety, and public interest, looking at all those considerations, and given what we've tried to explain today, there was a determination not to pursue a change in the status of the pipeline as an integrated interstate pipeline. And, so, we didn't pursue further any legal analysis. So, that's where the core legal analysis stands.

And, there has also been -- so, there has been some concern expressed that there isn't a more in-depth legal analysis. Whether, even if assuming that the Company was in favor of seeking a change of jurisdiction, for -- because one of the studies or a change in operation was seen to deliver benefits, it is not guarantied that such an application for change at the federal agency would be successful. There is no very specific case on point that gives, you know, an exact fact situation that Granite presents itself with a pipeline that crosses three states, where the gas flows both from Massachusetts, from Maine, from points in New Hampshire, through the system. There is -- you cannot point to any one point along the pipeline and conclude that gas entering into the state only stays within the state, gas flows across the boundaries, going both north and south. So, there's no exact fact pattern at FERC currently. So, it's not clear whether or not FERC would grant the exemption, unless there was some clear change in configuration that changed the nature of the interstate pipeline. So, it is an unknown, even if the Company willingly decided to seek such a change from the FERC.

So, because of the results in the study, the Company determined that it wouldn't be cost-effective to try to pursue having a more in-depth legal analysis. There was just no need to take that further.

With respect to regulatory costs, there has also been concern expressed by both participants in Maine and here in New Hampshire about the regulatory costs and the concern that regulatory costs that ultimately are borne by customers are higher, if the Company continues with its operation as a federally regulated pipeline, as opposed to somehow coming under state jurisdiction. We think that that's highly questionable. One is, it's not clear whether or not there would be any less regulatory filings. While there's clearly a cost to filings, if the pipeline were made part of the states, there are costs associated with the issues that we discussed, such as the Integrity Management, the Little Bay Bridge crossing, or the replacement of the disbonded pipes. And, so, the timing of recovery of those costs might be such to add to regulatory filings on the part of Northern, if it was an integrated pipeline. So, it's not clear that, just because you're at FERC, you're experiencing more or higher costs, regulatory costs, than you would if you're regulated by the states.

There are also additional cost considerations that have to be taken into account, and those are the allocation of costs, if there was an attempt to make the pipeline part of the Northern facilities and regulated by the states. Allocation issues have often, in the past, our understanding, at least under NiSource ownership, the previous ownership, have been somewhat thorny. And, while there may be best intentions at the outset to try to allocate those costs equitably between the states, it's not necessarily so. It's nothing that can be guarantied. And, there's a possibility of disputes down the road. And, the concern, on the part of the Company, is that, effectively, it may lose opportunities to recover costs because of differences between the states. And, it's a significant financial risk upon the Company to proceed in that manner.

So, we feel that the regulatory cost issue is not one that should be given much weight, in terms of a determination as to which direction to go, and it was mostly discounted, in terms of the analysis.

The other thing to point out, in terms of regulatory costs before the federal agencies, a lot of that is driven by the participation of intervenors. A significant part of a rate case cost is responding to discovery, both on the part of internal staff resources and if there are any external consultants hired by the Company in pursuing rate cases and similar cases. And, so, those are considerations.

If regulatory costs are -- as regulated costs have been raised as a concern, I mean, the Company did move forward in its filing at its last regulatory filing at FERC where it presented a plan to have, basically, an added tariff factor to account for the large construction projects that it was facing, and, therefore, to allow compensation through that factor and avoid rate cases. But that was not accepted or agreed to by the intervenors, by the states and by the public advocate's office, so that's a cost-saving opportunity that was lost. And, so, in order to recover the construction costs that we're talking about, the Company will have to file additional rate cases. And, we hope that there are mechanisms and procedures that can be employed to try to keep those costs at a minimum, and that the Company would certainly look in favor of trying to meet with the -- meet with the state staffs before filing, and try to see if there are issues that can be settled beforehand, and possibly try to approach FERC with a settlement of those issues. So, again, a lot of that depends on the willingness of the parties to engage in efforts like that and to try to keep costs at a minimum. It's not something that's wholly within the control of the Company.

And, that's all I have to say on that subject.

CHAIRMAN GETZ: So, then, we're prepared to move on for other comments? Anything further?

MR. MEISSNER: It might be worth just spending one minute on conclusions. I won't rehash anything we talked about. But I did want to bring it back to what we talked about at the beginning. Which was, we came into this study really from an engineering and planning perspective. That was the objective of the study. And, we approached this study from the standpoint of making a physical or operational change to the pipeline that would avoid costs that didn't otherwise need to be incurred. So, that was really the goal of the study.

I think the primary objective coming in was to de-rate the pipeline or reduce the operating pressure of the pipeline, in order that it would fall outside the definition of a jurisdictional transmission pipeline. And, we determined, I mean, coming into it, we thought that that would probably be feasible. We determined it's really not economically or operationally feasible.

We did also look at alternatives to change the configuration of the pipeline to avoid other types of costs, like Little Bay Bridge Project or the disbonded pipe and the Integrity Management costs. But, at the end of the day, what we found was that the pipeline, in its current configuration and operating at its current pressure, is the least cost alternative, without factoring in any of the qualitative things we talked about, like reliability, like operational benefits, like supply. All of those qualitative benefits also favor the pipeline in its current configuration. None of those were incorporated into the financial analysis itself.

So, from our standpoint, the pipeline in the current configuration is the clear winner, both on the basis of cost and on the basis of all the qualitative factors. And, while we did evaluate a few new scenarios, referred to as "15", "16", and we revisited 13A, none of those scenarios fundamentally change that conclusion from the original study. Thank you.

CHAIRMAN GETZ: All right. Thank you. Who would like to go next?

MS. FABRIZIO: I think it may be me.

CHAIRMAN GETZ: Ms. Fabrizio.

MS. FABRIZIO: Before I begin my more formal statement, I'd like to address a couple of the issues raised by the Company today. The Company counsel has suggested that the cost -- the project cost difference highlighted in Staff's memo are not as significant as they are in reality. But Staff would note that the fully loaded costs that were shown on Slide 16 today were not provided during the course of the study. And, when the Company filed its rate case at FERC four months later, Staff noted that the project costs had actually increased by about 30 percent. It was the cost differential in the FERC filing, as well as the anticipated increase in IMP costs occurring at changes that are going on at the federal level that triggered Staff to raise its concerns and look more closely at some of the issues in this proceeding during the course of the FERC rate case. We would also note that, as we've stated in the memo that was filed on November 18th, that, although the parties participated in discussions throughout the study process, and it was a collaborative effort to some extent, the final report itself represents the analysis and conclusions of the Company, and not necessarily that of either the Maine or New Hampshire staffs.

And, finally, on the scenario analysis that you saw presented today, regarding the most recent scenario changes and analysis, Staff did not actually see the results of that analysis until this morning. So, we will continue to look and reassure ourselves on the cost studies that we've done so far with respect to that analysis.

CHAIRMAN GETZ: Is that for 15, 16, and 13A?

MS. FABRIZIO: Yes. Okay. Since filing

its memo on November 18th, Staff has continued to work closely with the Company to resolve the issues raised in the memo. The most pressing being whether it's in the public interest to replace or retire the approximately 7 miles of disbonded pipe on the Granite System. The study filed as part of the merger proceeding in this docket did not include a look at the costs and benefits of retiring that section of disbonded pipe and operating the system at reduced pressure to avoid Pipeline Integrity Management costs. With the Company's cooperation in preparation for today's hearing, the analysis of the disbonded pipe project is now much closer to completion and the results preliminarily suggest that replacing the pipe may be the most cost-effective option at this time.

Staff and the Company analyzed the additional gas supply costs that would be incurred if the disbonded pipe were retired. And, our analysis indicates that those costs could exceed 2 million per year for at least the next eight years, which is when Northern's contract for PNGTS capacity expires. It is Staff's expectation that Pipeline Integrity Management costs are likely to increase significantly as a result of recent transmission line failures, in Marshal, Michigan; Romeoville, Illinois; Hanoverton, Ohio; and most notably in San Bruno, California. But those potential costs are not reflected in the analysis conducted thus far. As you've heard today, federal safety regulations require immediate Integrity Management assessments to be completed on all interstate transmission lines by 2012, with remedial action plans to be finalized and implemented based on the results of those assessments. Given the relative certainty of the additional gas supply costs, versus the uncertainty of the potential increase in Pipeline Integrity Management costs, the decision to replace the disbonded pipe at this time appears to be a reasonable one.

Another major project raised in Staff's memo concerns the section of pipe on the Little Bay Bridge, which must be removed when the bridge is being replaced. As you've heard, the Company plans to use horizontal drilling to lay pipe under the river, although the study found that abandoning that section of pipe and building a new gate station could be a cheaper option. That issue needs to be resolved. Though, the bulk of the work and associated expense for this project is not scheduled to occur until 2013, we heard today from the Company, as presented on Slide 36, that the alternative option of siting the Eliot Station in two years is apparently almost impossible. Staff would like to work with the Company to analyze the costs and benefits of the Little Bay Bridge Project as thoroughly as we did the Disbonded Pipe Project.

Also of concern to Staff is the Company's conclusion in the study regarding the jurisdiction issues raised in the merger proceeding and addressed on Page 42 of that study.

The study states, and I quote: "Unitil's decision to continue to operate Granite as an integrated, uninterrupted pipeline would preclude Granite from filing for abandonment of Granite's FERC certificate based on a changing of its configuration to two intrastate pipeline segments. Moreover, as the Granite Study has led Unitil to a conclusion that de-rating the pipeline and filing for an exemption from PHMSA regulation, or separating the pipeline at the border and seeking exemption from FERC regulation are not the most effective long-term solutions for Northern and Granite or Northern and Granite customers. Unitil has not identified any other reasons which would justify a change in ratemaking jurisdiction for Granite."

Staff's preliminary review of keeping the pipeline a distribution pipeline, rather than a transmission pipeline, was based on the following factors:

Northern Utilities recently expended approximately 450,000 to reduce operating pressure on intrastate pipelines from transmission level to distribution level, so as to avoid Integrity Management costs for a five mile segment between Dover and Rochester.

Second, a potential avoidance of an estimated $5 million of incremental capital expenditures between 2011 and 2013 are considered possible by retiring the disbonded pipeline and operating the pressures at distribution pressures.

Third factor was a potential avoidance of replacement of all mainline valves with remote operated valves. This remote operation requirement would apply only to transmission pipelines, not distribution lines. And, the cost is conservatively estimated to be about between 1.9 to 3.8 million in New Hampshire and Maine.

And, fourth, the potential avoidance of hydrostatic testing of transmission pipelines where records are untraceable, incomplete, or unverifiable. This federal recommendation is estimated to possibly result in a cost of $3.5 to $5 million to occur prior to 2014.

The legal analysis in the Granite study

does not consider the possibility that even -- excuse me -- without changing Granite State's configuration or operations, FERC could grant state jurisdiction if the Company were to petition for it. Staff is not and has never suggested that we would ask this Commission to direct the Company to change jurisdiction. And, moreover, the federal statutes indicate that FERC can hold a hearing on the determination of service area under a Section 7(f) that was referred to earlier upon its own motion.

The regulatory and legal analysis contained in the Final Study does not consider the additional regulatory costs of operating under two regulatory regimes; that is Northern, under the state regime, and Granite, under the FERC regime. Granite's recent rate filing at the FERC reflected an annual regulatory expense of $83,000 and estimated rate case expense of over half a million dollars. In response to Staff Data Request 6-178 in this proceeding, Granite expects to file a rate case at FERC in each of the next three years, at a cost of 350,000 per filing. In addition to Granite's rate case expenses, Northern customers bear the cost of state intervention. There are no shippers to represent the customer interests in Granite's rate proceedings before FERC, because Granite's affiliated customer, Northern, takes over 90 percent of Granite's capacity and Northern itself does not intervene. Indeed, to do so would not be in the best interest of its parent company. Were it to do so, but not contest any of Granite's proposed costs, Northern's intervention would be essentially ineffective to protect the interests of its ratepayers. As a result, New Hampshire ratepayers are limited in representation to the New Hampshire and Maine state commissions and consumer advocates, rather than direct and unaffiliated customer stakeholders. Another disadvantage to New Hampshire ratepayers in Granite remaining under FERC jurisdiction is the lower level of scrutiny involved in a FERC proceeding, a result of resource scarcity, rather than FERC intention, but a result that is more likely to lead to ever increasing rates borne by New Hampshire ratepayers.

Not only are regulatory proceedings before FERC expensive, the costs of which are passed directly through to ratepayers, the continued operation of the Granite pipeline at transmission pressure under FERC jurisdiction raises additional issues, such as the costs associated with meeting federal Integrity Management requirements of transmission pressure pipelines, as mentioned earlier, and what Staff believes is the lower level of scrutiny over safety management, as well as rate base and revenue requirements, than would occur under state jurisdiction. Staff believes that the Granite State pipeline more appropriately fits under state jurisdiction, rather than FERC, with only 87 miles of pipe and only three firm customers, one of which, Northern, holds 93 percent of the firm capacity as an affiliated customer.

Page 20 of the Commission's Order Number 24,906, dated October 10th, 2008, cites the following language from the settlement in the underlying docket: "The purpose of the study will be to assess whether customers of Northern and Granite would be better served by integrating Granite and Northern and/or otherwise reorganizing them and their operations." Staff believes that customers would certainly benefit from eliminating half a million dollars a year of federal regulatory expenses.

Overall, the study has been a valuable exercise, and both the Company's and Staff's understanding of the Granite system has been greatly enhanced, in particular by our more recent collaborative efforts since the filing of Staff's memo in November. That said, the explicit goal of the Study was to determine what operational scenario is in the best interest of Northern and Granite's customers, and Staff believes the Report falls short in that respect. We believe that the Little Bay Bridge Project needs further analysis, as does the issue of whether customers are better served if Granite were under state jurisdiction. Unitil's conclusion that there should be no change in regulatory jurisdiction is not supported by the analysis provided thus far.

It is Staff's recommendation that further inquiry into those issues is warranted. We therefore recommend that the Commission open an investigation into these matters, but allow the Staff and the Company to work together on the issues raised here, as we are doing with respect to the disbonded pipe project, and report back to the Commission before the Company files its anticipated rate case petition at FERC in the second quarter of this year. We also recommend that, to the extent the jurisdiction and related affiliate issues remain unresolved, they be included in the scope of the rate case anticipated to be filed by Northern this spring.

And, Mr. Chairman, with your permission, I would like to give the microphone to Randy Knepper, to respond to some of the issues raised regarding reliability and one-way flows earlier in the Company's presentation.

CHAIRMAN GETZ: Okay. Mr. Knepper.

MR. KNEPPER: Yes. You heard a lot today about, I guess, reliability and safety. And, there is a big difference of opinion between the Company and Staff as to how one weights what the impact is for one-way flows. Unfortunately, here in New Hampshire, we have a history of having, given the geography of where our communities are and where the pipelines are, we have a lot of places where there's one-way flows. The majority of the EnergyNorth system is, once you get off the Tennessee Gas pipeline that comes into this state, they have one-way flow from right here in Concord, up to seven communities up north. There's one-way flows going into -- from Windham to Nashua. There's one-way flows throughout the system. And, that's not unusual. And, so, because of that success, I mean, we look at that and we have not had a tremendous amount of accidents or incidents in the past or reliability issues. So, we take that into account and factor that into when you look at the reliability of these things.

If you look at the Seacoast area, where Unitil serves or Northern serves, you know, the Salem distribution system is a one-way flow. Even after the study, it's going to continue to be a one-way flow. It's fed from one pipeline. If you look at these green areas on this, looking up at Rochester, there's one-way flows. So, it is the nature of what we have here. And, so, although we don't ignore it, we just may not emphasize it to the same degree that the Company does, about having to have redundant systems and totally reliable things.

As far as the safety impact, to me, the safety impact is the same. You have to be -- you have to operate a safe system, that's the ticket to get in the door, no matter what the condition is or the geography of the pipeline. So, you know, we are not requesting them to do redundant pipelines and looping systems everywhere; we don't do that. We make sure that what they have and what they have and operate is done in a safe manner. So, I don't find that the safety and the reliability, I do find that they're distinct issues.

And, really, what it boils down for me is, you know, we have two big buckets, either you're classified as "transmission" or you're classified as "distribution". And, as Lynn mentioned in her statement, San Bruno, California and the four other transmission pipeline incidents that have occurred since the study has taken into effect are game-changers. I mean, it's literally going to change the industry. And, it's going to change it, and it's going to be very expensive.

There's going to be more and more onerous requirements under Integrity Management for those in transportation, and so -- I mean, transmission lines, than those in distribution. So, that really was the onus, is to look at it while this study was going on, and that's why we did some requests later on to factor those things in. Because when we -- they weren't really part of it when we initially took it out, took the study upon itself. So, it was a snapshot in time, but this -- the snapshot is changing, the landscape around it is changing. And, so, we felt -- I do feel that the study doesn't necessarily reflect all those costs. They're very difficult to, you know, put a precise number on, but it's definitely going to be large.

Unfortunately, I'm not so sure that the gas supply issues that they have and the supply costs, that they're going to outweigh those things, because they're very onerous to overcome as a -- in the review. And, so, it wasn't until those, I don't know, I would say those gas supply costs really came out to the forefront within the last, I don't know, couple weeks, is that we were really able to pin those down through the help of our staff, and Unitil has been very forthcoming in that, that it really was able to emphasize the degree of what those existing contracts are and how much of an impact they have. So, that's when things really came into being.

But the whole point was, is to try to avoid costs for Northern Utility customers in the end by looking at that distribution -- that distribution level requirement. And, one of the things that I do think is, from our take, it wasn't as far -- when we initially looked at it, it was pretty far apart. But, when you start throwing these other costs on there, it gets a lot closer. What tips it back in favor, I think of Unitil and keeping it as it is, those -- I call them "gas supply contracts" that are in existence with PNGTS that are going to be a problem, where you can't move the gas supply around as easily as you could before.

So, I guess that's all I have to say.

CHAIRMAN GETZ: Thank you. Anything else, Ms. Fabrizio?

MS. FABRIZIO: No thank you.

CHAIRMAN GETZ: Questions?

CMSR. IGNATIUS: I do. I have a couple of questions. I'm not sure if they -- who they relate to, so I'll leave you to divvy up who you think best. One is on the disbonded pipe. And, is there any -- would you agree with the Company's description that the location of the disbonded pipe is this particular area that was coated after it was in place? And, I guess that was leading to a suggestion that you wouldn't have that situation in other parts of the pipeline? Or, maybe put more directly to you, are you aware of any other locations where there are indications of the same problem or you think there may be the same problem?

MR. KNEPPER: Well, I guess I kind of heard for the first time today that NiSource had given them, Unitil, knowing about that disbonded pipe section, we looked at that initially in the study and kind of focused around there, looked at some of these scenarios earlier. It wasn't until late in the report that that was actually, you know, in the last review that it was kind of mentioned, it was kind of mentioned that it was there. It does cause a question as to, that occurred in what you call a "low consequence area", I guess, where there's not a lot of population. But, if it's a characteristic of how it was applied in the field, you know, it questions one -- whether those same application/construction techniques of applying that coating were done elsewhere on that pipeline. Because, if you look at the history of this pipeline, and you look at the dates and the vintages, it could be in other places, and it may not have just -- just may not have shown up yet.

CMSR. IGNATIUS: All right.

MS. FABRIZIO: Commissioner Ignatius, if I could just say, --

CMSR. IGNATIUS: Sure. Go ahead.

MS. FABRIZIO: -- the Staff has been pretty much limited to the information provided to us by the Company. So, perhaps the Company would prefer to respond directly to that question.

CMSR. IGNATIUS: All right.

MR. MEISSNER: Tim.

MR. BICKFORD: That segment of pipeline was -- actually was used pipe that was acquired, I believe, back in the late '50s or maybe early '60s, and it was acquired from the government. And, it was the -- the coating was field-applied when it was installed. And, that is the only segment that has field-applied coating.

CMSR. IGNATIUS: Thank you. On the issue of the possibility of directional drilling at the Little Bay Bridge, does Staff have any concern about the high-velocity current that the Company referenced and what that might mean for having an underground pipeline running there?

MR. KNEPPER: Probably not in what

you're envisioning. The reference to the high current is for them to do inspections if it was aboveground. And, so, it would be, I don't know, not -- it would be challenging, I guess, is probably -- Kevin, that's probably how he would state it is, versus if it was still water and they had easier access. But, going underneath and doing the horizontal directional drill, I don't believe the currents are going to have any effect on that. What's going to affect that more is what kind of granite you hit and the bedrock that's underneath there. Until those test bores are done, until it's actually in the middle of being able to do it, will you find out how accurate all those assessments or estimates were.

They did say that, at the Piscataqua River, when the -- I guess it's the joint facilities were put in, that they had a pretty successful one. But, if you just go down the street, looking at in Durham, when UNH ran 30 percent of their horizontal drills, some of them were very much more expensive than what they anticipated because of the rock that they hit. So, New Hampshire is quirky. You can have a problem of smooth sailing on one side of the street, and go down 300 feet, and it can be as difficult as possible. So, it's tough for them to estimate, but the cost could be definitely higher. It's all dependent upon what happens.

CMSR. IGNATIUS: One other question, and it's one of timing. Ms. Fabrizio, you suggested that an investigation would be appropriate, but you also know there are deadlines coming forward for the Company, both on the assessment and on the Little Bay Bridge construction. How do you see those deadlines and a Commission investigation working together in a way that's ultimately successful?

MS. FABRIZIO: Well, we haven't quite thought through the exact timing of possibilities. But, because this is an open docket, and we have been working closely with the Company on resolving some of the issues that we've been discussing today, perhaps it would be most practical to continue working with the Company and report back to the Commission at some point before its anticipated rate filings, either at the FERC or here at the Commission. And, an investigation, I suppose, could be in a new docket, after that point, if the Commission agrees that the issues warrant further investigation.

CMSR. IGNATIUS: Well, I guess -- but I still don't quite follow, if, let's say the investigation were to take six months, maybe a little more, maybe less, but how does the Company then -- does it still have enough time to implement construction plans with Little Bay Bridge, one way or another, if that were to happen, or to get on with the assessments that need to be done for the rest of the system to meet that deadline? Are they, by having an investigation, do we put out for too long the next steps that have to happen under -- it sounds like on many of the scenarios some of those steps are going to have to happen, and in some cases they wouldn't have to happen. But how does the timing fit? Do we have the luxury of another six plus months to study things? Or, are there waivers to some of the deadlines that could be requested? Is that another way to try and continue to investigate and deal with the deadlines that are now present?

MR. FRINK: I would like to say the Little Bay Bridge Project I think could be addressed very quickly. A major consideration is the gas costs. With what we've done on the disbonded pipe piece, I think we're well along the path to where we can do a fairly quick turnaround on that issue, which weighs heavily in the decision. So, I don't think that we're looking at anything near a six-month investigation, I think something that could be wrapped up fairly quickly, within a month or two.

And, as far as the regulatory issues, I'm not sure when the Granite filing is -- when the Company intends to make that Granite filing. But that doesn't have the same urgency. And, I don't think there's, to be honest with you, I'm not too sure we could come to an agreement on that one. And, I don't think there's a lot of research to be done in that. But one thing I would be interested on that piece, it's not the same urgency in that, and also Maine's -- there's been a request for Maine to open an investigation, their Commission to open an investigation in a request by the OPA there. So, I'm somewhat interested to see what happens there.

So, I don't see us inhibiting their ability to do what they need to do to meet their construction projects and IMP requirements, especially since we've put the disbonded pipe, resolved that pretty much. And, as far as the regulatory piece, I just -- I think we can take our time on that to some degree. And, we do have a couple of dockets that we know are coming up, and it may be that, if we can't resolve them, we can address them there.

CMSR. IGNATIUS: Thank you.

CHAIRMAN GETZ: Okay. Then, Mr. Traum,

do you have a comment?

MR. TRAUM: No. The OCA does not have a position.

CHAIRMAN GETZ: Okay. Thank you. Gentlemen, anything, a public comment?

MR. EMERTON: No. Not at this time.

CHAIRMAN GETZ: Anything further then today?

(No verbal response)

CHAIRMAN GETZ: All right. Hearing nothing, then we'll close the status conference and take the recommendations under consideration. Thank you, everyone.

(Whereupon the status conferenced ended at 1:46 p.m.)